HYDRO ONE INC.
ANNUAL CONSOLIDATED FINANCIAL STATEMENTS

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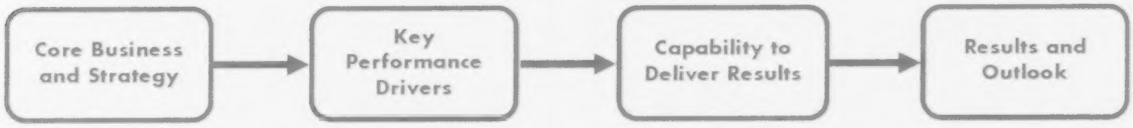
We prepare our Consolidated Financial Statements in Canadian dollars in accordance with accounting principles generally accepted in Canada. The following discussion is based upon our Consolidated Financial Statements for the years ended December 31, 2011 and 2010.

EXECUTIVE SUMMARY

We are wholly owned by the Province of Ontario (the Province), and our transmission and distribution businesses are regulated by the Ontario Energy Board (OEB). Our mission and vision have been refined to recognize the unique role we play in the economy of the province and as a provider of critical infrastructure to all our customers. We will be an innovative and trusted company delivering electricity safely, reliably and efficiently to create value for our customers. We operate as a commercial enterprise with an independent Board of Directors. Our strategic plan is driven by our values: health and safety, excellence, stewardship and innovation. Safety is of utmost importance to us because we work in an environment that can be hazardous. We take our responsibility as stewards of critical provincial assets seriously. We demonstrate sound stewardship by managing our assets in a manner that is commercial, transparent and values our customers. We strive for excellence by being trained, prepared and equipped to deliver high-quality service. We value innovation because it allows us to increase our productivity and develop enhanced methods to meet the needs of our customers. In 2011, we continued to focus on our core businesses and our commitment to our customers, substantially maintained and improved our performance in various key areas of our company, and made important contributions to the rebuilding of Ontario's core infrastructure while continuing to meet the requirements of the Green Energy Act (GEA).

We manage our business using the following governance structure:



Core Business and Strategy

Our corporate strategy is based on our mission and vision and our values. Our strategic goals, which are discussed in the section Our Strategy, encompass the core values that drive our business. Our strategy touches every part of our core business: health and safety; our customers; innovation; the reliability and efficiency of our systems; the environment; our workforce; shareholder value; and productivity.

Key Performance Drivers

We have identified performance drivers critical to achieving our strategic goals. Each driver is specific to measuring our success in achieving a specific goal. We establish specific performance targets against each driver every year aimed at achieving our strategic goals over time. For example, we track the number of customers being billed on time-of-use (TOU) pricing as an indication of our commitment to continuous innovation and use the Collaborative Planning Index as an indication of our commitment to productivity and cost-effectiveness. Reduced carbon emissions demonstrate our commitment to protecting the environment. These and other key performance drivers are included in our discussion of our performance measures in the section Performance Measures and Targets.

Capability to Deliver Results

We continue to use a balanced scorecard approach as we strive to manage our key performance drivers and deliver results each and every year. In 2011, we set 17 stretch targets and we met or exceeded 13 of them, consistent with our prior year results when we met or exceeded 14 of 18 stretch targets. We will enable clean and renewable energy in Ontario with the implementation of our Bruce to Milton Transmission Reinforcement Project that will create Ontario's new clean energy corridor. We successfully met our target for customers consuming power on TOU pricing by June 30, 2011. By the end of the year, we had over 1,190,000 customers consuming power on TOU pricing. We exceeded our target for minimizing the duration of unplanned customer interruptions within our Transmission Business. The results of our efforts are fully discussed in the section Performance Measures and Targets. Our capability to deliver results in each of our strategic areas is limited by risks inherent in the regulatory

environment, our business, our workforce and the economic environment. These risks, as well as our strategies to mitigate them, are discussed in the section Risk Management and Risk Factors.

Results and Outlook

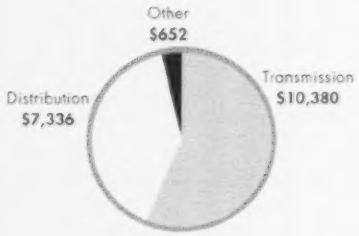
During 2011, our financial fundamentals remained strong, with current year net income of $641 million. Our OEB-approved revenue requirements for our transmission and distribution businesses for 2011 were $1,346 million and $1,218 million, respectively. Approved rates support our work programs required to sustain our critical infrastructure and invest in a sustainable electricity system that supports renewable and cleaner generation. We maintained "A" category credit ratings and successfully issued $700 million in debt financing, while repaying $500 million of debt maturing in the year. A full discussion of our results of operations and financing activities can be found in the sections Results of Operations and Liquidity and Capital Resources.

In 2011, we invested more than $1.4 billion in capital expenditures to improve system reliability and performance, address an aging power system, facilitate new generation and improve service to customers. Capital expenditures for the next few years include those required to build critical infrastructure identified in the Long-Term Energy Plan (LTEP), based on recommendations from the Ontario Power Authority (OPA) and expenditures to address aging infrastructure. Our future capital expenditures are more fully described in the section Future Capital Expenditures.

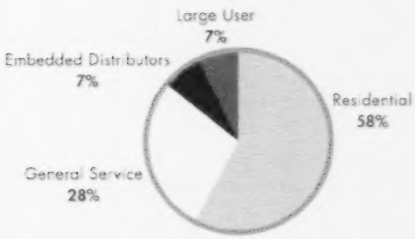
OVERVIEW

Transmission

Substantially all of Ontario's electricity transmission system is owned and operated by our company. Our transmission system forms an integrated transmission grid that is monitored, controlled and managed centrally from our Ontario Grid Control Centre. Our system operates over relatively long distances and links major sources of generation to transmission stations and larger area load centres. In 2011, we earned total transmission revenues of $1,389 million primarily by transmitting approximately 141 TWh of electricity, directly or indirectly, to substantially all consumers of electricity in Ontario. Our transmission system is one of the largest in North America, and is linked to five adjoining jurisdictions through 26 interconnections, through which we can accommodate imports of about 4,600 MW and exports of approximately 6,000 MW of electricity. In terms of assets, our Transmission Business is our largest business segment, representing approximately 57% of our total assets.



Total Assets
December 31, 2011
(CAD $ millions)



2011 Distribution Revenues

Distribution

Our distribution system is the largest in Ontario and spans roughly 75% of the province. We serve approximately 1.4 million rural and urban customers, local distribution companies (LDCs) connected to the distribution system, and 435 large user customers. We also operate small, regulated generation and distribution systems in a number of remote communities across Northern Ontario that are not connected to Ontario's electricity grid. We earned total distribution revenues in 2011 of $4,019 million. As illustrated in the accompanying chart, over half of our distribution revenues are earned from our residential customers. In terms of assets, our Distribution Business represents approximately 40% of our total assets.

Other

Our other business segment contributed revenues of $63 million in 2011 and has assets of about $652 million, which represents 3% of our total assets. This segment primarily represents the operations of our wholly-owned subsidiary,

Hydro One Telecom Inc., which markets fibre-optic capacity to telecommunications carriers and commercial customers with broadband network requirements, including a dedicated optical network providing secure, high-capacity connectivity across numerous health care locations in Ontario.

Our Strategy

Our corporate strategy is based on our mission and vision and our values. Our mission and vision is to be an innovative and trusted company delivering electricity safely, reliably and efficiently to create value for our customers. Our values represent our core beliefs:

Health and safety: Nothing is more important than the health and safety of our employees, those who work on our property and the public.

Excellence: We achieve excellence through continuous training, ensuring we are prepared and equipped to deliver high-quality and cost-effective service, with integrity.

Stewardship: We invest in our assets and people to build a safe, environmentally sustainable electricity network in a commercial manner.

Innovation: We innovate through new processes, people and technology to allow us to find better ways to meet the needs of our customers.

We have eight strategic objectives that are inextricably linked. They drive the fulfillment of our mission and vision.

Creating an injury-free workplace and maintaining public safety. Health and safety must be integrated into all that we do. We must continue to create a passion for preventing injury. We will strengthen our already strong safety culture through our Journey to Zero initiative and achieve world-class results. We will continue to reinforce that nothing is more important than the health and safety of our employees.

Satisfying our customers. We will meet our commitments, make customers our focus in our planning, communicate effectively, coordinate across lines of business, and maximize opportunities to improve our corporate image.

Continuous innovation. Innovation represents one of our core values and is critical to achieving our mission and vision. Over the next two decades, we will install innovative solutions that improve the reliability and efficiency of the transmission and distribution systems and provide our customers with more capability to manage their power costs. The Advanced Distribution System (ADS) is a key element in our investment in innovation and will improve operation of our grid assets and deliver further value to our customers.

Building and maintaining reliable, cost-effective transmission and distribution systems. Our transmission strategy is to provide a robust and reliable provincial grid that accommodates Ontario's emerging generation profile, manages an aging asset base and meets demand requirements through prudent expansion and effective maintenance. Our distribution strategy is focused on: incorporating ADS technology to provide greater visibility; increasing control and improving customer service; supporting the connection of renewable energy sources; seeking efficiencies through leveraging technology and operational experience from our transmission system; providing reliable and cost-effective service over a diverse geography; and remaining open to opportunities to rationalize the distribution sector.

Protecting and sustaining the environment for future generations. Consistent with our value of stewardship, we play a central role in reducing Ontario's carbon footprint through the delivery of clean and renewable energy and through measures that allow our customers to manage and reduce their energy use.

Employee engagement. We believe our primary strength is the capability of our people. In order to sustain this advantage, we must address the issues of corporate culture, labour demographics, diversity, development of critical core competencies and skill and knowledge retention. Our labour strategy will enable us to make significant gains in the areas of labour flexibility, productivity improvement and cost reduction.

Maintaining a commercial culture that increases value for our shareholder. We are committed to keeping rates as low as possible for our customers, and delivering income and dividends to our shareholder. This is possible through our focus on reducing costs, managing our assets effectively and increasing productivity.

Achieving productivity improvements and cost-effectiveness. To achieve our mission and vision, we must constantly strive for productivity through efficiency and effective management of costs. Productivity is key to meeting our other strategic objectives and, in particular, to achieving value for our customers and our shareholder.

We recognize the pivotal role innovation will play in building a smart electricity grid that supports a clean environment for Ontario. We are committed to becoming the industry leader in putting innovative solutions to work for the well-being of Ontario's economy and its residents.

Performance Measures and Targets

We measure and target our performance by using a balanced scorecard approach. Key performance drivers are closely monitored throughout the year to ensure that we achieve our strategic objectives. In 2011, we met or exceeded 13 of 17 stretch targets. Overall, we are making progress towards achieving our strategic goals.

Creating an injury-free workplace and maintaining public safety

Safety is the primary focus of our company and is our first key strategic objective. The safety of our employees is paramount. For 2011, we established medical attentions, that is, injuries that require treatment by a medical practitioner (beyond first aid), as the performance measure for this strategic objective. The medical attentions measure reflects incidents that are reported to the Workplace Safety Insurance Board and is calculated by the number of attentions per 200,000 hours worked. In 2011, we set a target of no higher than 2.2 incidents per 200,000 hours worked. In an effort to achieve this target, we engaged in a number of activities such as, among other things, continued emphasis on improving health and safety through face-to-face sessions, continuation of our Journey to Zero initiative, better monitoring of mandatory skills and safety training, enhanced driver training/evaluation program and field coaching to increase the expectations from supervisors and staff. The number of incidents in 2011 increased and as a result we did not meet this target.

Satisfying our customers

Customer satisfaction measures the degree to which our transmission and distribution customers are satisfied with the service they receive from our company. Corporate reputation is also a key influencer in customer satisfaction. We continue to focus on improving our reputation. Customer satisfaction is measured on the results of various customer surveys conducted on our behalf by independent third parties. In 2011, for transmission customers we targeted a customer satisfaction rate of 89% and did not meet this target. For our distribution customers, we targeted a satisfaction rate of 85%, but did not meet this target.

Despite these results, we were honoured by the E Source Review as ranking third in Canada among electric and gas utilities in delivering positive customer experience through our automated phone system - interactive voice response system. Additionally, we received the Canadian Electricity Association's (CEA) Sustainable Electricity Social Responsibility Award in recognition of our leadership in engaging our stakeholders. One of the projects recognized by this award is our outreach at fairs across the province to deliver the "Understanding Your Power" event to customers and stakeholders.

Focusing on continuous innovation to ensure a modern, flexible and advanced distribution system

We are committed to identifying and providing innovative solutions that will improve the reliability and efficiency of electricity delivery and allow our customers more capability to manage their power costs. Billing customers on TOU rates is the last step in the implementation of our Smart Meter Project. We established a milestone of 1,050,000 customers consuming power on TOU rates for 2011. The Green Grid Enablers are an integral part of meeting the GEA and our strategy towards embracing innovation. Our target is a percentage completion of a number of milestones for the combined Smart Meters TOU Billed and Green Grid Enablers which are projects designed to meet the objectives of the GEA. Our target was to complete 90% of all milestones established for all these initiatives by year end. For 2011, we exceeded our target.

We were honoured and recognized with two awards in 2011. We received the Apex Award, given by the Utilities Telecom Council, in recognition of how our communications systems demonstrate excellence, innovation and service to the communities we serve and in recognition of the installation of six WiMax base stations to provide wireless communications for testing the smart grid applications. As well, we received the Excellence in Project Management Award, given by Utilimetrics, in further recognition of our smart meter deployment and conversion of customers to TOU billing.

Building and maintaining reliable, cost-effective transmission and distribution systems

We aim to build and retain public confidence and trust in our operations, as stewards of Ontario's electricity grid. In 2011, we continued our focus on this strategic priority by investing in the key assets of the electricity delivery system and by operating the existing system for customers in a safe, reliable and efficient fashion. Transmission reliability is measured through the frequency and duration of unplanned customer interruptions. Distribution reliability is measured through the duration of customer interruptions. The results of our performance are compared with other large sized members of the CEA. Reliability is influenced by weather patterns and accordingly, to achieve results, we require good performance from both our transmission and distribution systems. We are conscious that businesses of all sizes require reliable service to allow them to deliver their products and services and that customers' expectations are for a reasonably limited duration of interruption.

With respect to transmission, in 2011, we targeted 0.25 interruptions per delivery point for our frequency of unplanned interruptions. The actual year-end frequency of unplanned customer interruptions was 0.21. We more than met the target.

For duration of unplanned customer interruptions on the transmission side, the target was 15 minutes per delivery point. The duration of unplanned customer interruptions at year-end was 8.9 minutes. We more than met the target.

On the distribution side, the target for 2011 for the duration of customer interruptions was set at 6.8 hours per customer. Due to a number of storms in December 2011 interrupting a large number of customers over several days, the duration of customer interruptions over the year was negatively impacted. As a result, the duration of interruptions was 6.9 hours, or 0.1 hours higher than target; we did not meet our target.

Protecting and sustaining the environment for future generations

Our initiatives to protect the environment are aligned with the GEA and show our commitment to the delivery of renewable clean energy. We developed three key performance measures for 2011: (i) LTEP and the Bruce to Milton Transmission Reinforcement Project; (ii) greenhouse gas reduction and (iii) Conservation and Demand Management (CDM).

The Province's LTEP, released in 2010, indentifies 5 priority projects to be completed by 2018 that will ensure that the growing mix of renewable generation can be reliably transmitted across the province. Under the LTEP, we are to develop three of these projects. These three priority projects and our continued work on the Bruce to Milton project align with our commitments to protect the environment and support the GEA. For the LTEP, we targeted completion of milestones leading to the successful completion of the development phases of the three projects. Regarding the Bruce to Milton Transmission Reinforcement Project, we targeted a 90% completion of critical milestones by selected dates within 2011. We exceeded our target with respect to the LTEP projects and the Bruce to Milton Transmission Reinforcement Project for 2011.

With respect to greenhouse gas reduction, we established a target of 2,736 metric tonnes of greenhouse gas removed through our initiatives related to our (a) vehicle fleet program (150 tonnes), (b) sulphur hexafluoride gas (SF_6) (2,536 tonnes), and (c) facilities electricity (50 tonnes). We achieved an aggregate of 3,555 metric tonnes of greenhouse gas removed from these initiatives, thus exceeding our target.

Regarding CDM, we are required to comply with the OEB's CDM Code and achieve targets established for us during the period of 2011 to 2014. For 2011, we established a corporate plan to achieve 90% of the milestones we set for those programs for 2011. We exceeded our target for 2011 by completely meeting all milestones.

Employee engagement

Our greatest assets are our employees. We continue to focus effort, specifically in employee and management development activities, on increasing employee engagement throughout our company. An engaged workforce is one in which employees embrace the corporate values of safety, stewardship, excellence and innovation. The process of measuring and improving such engagement began in 2008 by means of an employee engagement survey administered by an independent third party expert and the target is to improve the grand mean score year-over-year. The response rate in 2011 was the largest received to date, with an 86% participation rate. The target of improving the grand mean score to 3.79 (out of 5) in 2011 from the actual result of 3.70 in 2010 was achieved as we exceeded our target with a score of 3.94.

Maintaining a commercial culture that increases value for our shareholder

Achievement of strong financial performance is measured by our two performance measures of net income and a strong credit rating. Our targets were $613 million net income and an "A" category credit rating. Net income for 2011 was $641 million; we met our target. Our long-term credit ratings provided by Standard & Poor's (S&P), Moody's Investors Service Inc. and DBRS Limited met the targeted "A" rating category. Maintaining an "A" category credit rating allows us to have access to long-term debt markets on a cost-effective basis, which is even more critical in the current financial market environment and given our capital requirements over the medium term.

Achieving productivity improvements and cost-effectiveness

One of our strategic objectives is to be productive through efficiency improvements and effective management of costs. The measures for this objective for 2011 were: transmission unit cost, distribution unit cost, Collaborative Planning Index and Cornerstone savings.

To meet our goals regarding transmission unit costs and distribution unit costs, we benchmarked our company against electricity industry-wide measures of productivity. The two most comparable benchmark measures are transmission unit cost, calculated as sustaining capital and operation, maintenance and administration (OM&A) per asset on a percentage basis, which is expressed as cost per asset value for the Transmission Business and distribution unit cost, calculated as capital and OM&A per kilometre of line, which is expressed as cost per line length for the Distribution Business. These were set as our performance measures. Our objective with our ongoing work and investment program is to maintain and improve our assets such that delivery reliability for our customers is maintained or improved and to be productive in how we do that work. To benchmark our performance and monitor our productivity year-over-year, we set cost targets which are measured within a range of plus or minus 5%. Our transmission unit cost target was set at 5% and we met this target. Regarding our distribution unit cost, our cost target was set at $6,800 per kilometre of line and we also met this target.

The Collaborative Planning Index is a measure of the effective workflow between lines of business and the resulting efficiencies enabling field crew productivity. The Collaborative Planning Index is based on the average of three metrics: release of work, which is the release of funds at the program and project level for work defined and agreed to by the operations groups; planning index, which is the percent measure of the total number of material orders entered into the system divided in accordance with lead times agreed to by the stakeholders; and order fill rate, which is the percent measure of the total number of material orders divided into the number of line orders that have been delivered to the right location at the right time. For 2011, we set the target for the average of the three metrics at 87% and we exceeded this target.

Cornerstone is our phased replacement of key enterprise information technology systems. Savings from this initiative are derived by looking at a wide range of processes to identify savings across the various lines of business. Our target for 2011 was $38.5 million in savings and we achieved $41.3 million in savings through strategic sourcing of materials, reduction in employee headcount, and reduction in the number of information technology applications and their attendant support costs, thereby exceeding this target.

REGULATION

Our electricity transmission and distribution businesses are licensed and regulated by the OEB. The OEB sets rates following oral or written public hearings. Our transmission revenues primarily include our transmission tariff, which is based on the uniform province-wide transmission rates approved by the OEB for all transmitters across Ontario. Our distribution revenues primarily include our distribution tariff, which is also based on OEB-approved rates, and the recovery of the cost of purchased power used by our customers. Consequently, our Distribution Business does not have commodity price risk. Transmission and distribution tariff rates are set based on an approved revenue requirement that provides for cost recovery and includes a return on deemed common equity. In addition, the OEB approves rate riders to allow for the recovery or disposition of specific regulatory assets and liabilities over a specified timeframe.

Electricity Rates

Under the current market structure, low-volume and designated consumers pay electricity rates established through the Regulated Price Plan (RPP) and wholesale electricity consumers pay a blend of regulated, contract and wholesale spot market prices. The OEB previously set prices for RPP customers based on a two-tiered electricity pricing structure with seasonal consumption thresholds. Currently, it also sets prices for RPP customers based on a three-tiered electricity pricing structure with TOU thresholds. Unexpected shortfalls or overpayments associated with the RPP are temporarily financed by the OPA. Prices are reviewed every six months and may change based on an updated OEB forecast and any accumulated differences between the amount that customers paid for electricity and the amount paid to generators in the previous period.

Effective May 1, 2010, we started migrating our customers to TOU rates. On August 4, 2010, the OEB issued a Final Determination to mandate TOU pricing for RPP consumers by establishing a mandatory TOU date for each electricity distributor. This Final Determination mandated that all eligible RPP customers be transitioned to TOU pricing by June 2011. On September 16, 2010, we filed an application with the OEB for an exemption from the mandated TOU pricing, affecting approximately 150,000 customers located in very rural and sparsely populated portions of our service territory that are currently out of reach of our smart meter telecommunications infrastructure. In early 2011, the OEB approved our request for an extension until the end of 2012. As at June 30, 2011, we had over one million customers consuming power based on TOU pricing, meeting our OEB target. By the end of 2011, we had transitioned the majority of our remaining customers to TOU rates. For the final 150,000 exempted customers, we continue to evaluate different options.

As announced in the 2010 Ontario Economic Outlook and Fiscal Review, the Province introduced the *Ontario Clean Energy Benefit Act, 2010*, which is designed to assist Ontario electricity consumers through the transition to a cleaner electricity system. Under this Act, eligible residential, farm and small business consumers receive financial assistance in the amount of a 10% credit with respect to the total cost of electricity on their bills, including tax. This assistance is being provided to eligible customers for a five-year period beginning January 1, 2011. In January 2011, our company issued its first bills to customers with this credit applied to their electricity costs.

Customers who are not eligible for the RPP and wholesale customers pay the market price for electricity, adjusted for the difference between market prices and prices paid to generators under the *Electricity Act, 1998*. The Independent Electricity System Operator (IESO) is responsible for overseeing and operating the wholesale market as well as ensuring the reliability of the integrated power system.

GEA and LTEP

In addition to the oversight role of the OEB, and the market-monitoring and coordination role of the IESO, the OPA was created through the *Electricity Restructuring Act, 2004* to ensure the long-term supply of electricity, facilitate load management and conservation, and assist with the stability of rates for RPP customers, among other roles. As part of its mandate, and consistent with the Province's direction regarding supply mix, the OPA developed the Integrated Power System Plan (IPSP) and submitted it for OEB review and approval in August 2007. On September 17, 2008, the Province directed the OPA to review a portion of its proposed IPSP focusing on renewable energy and conservation as well as to undertake an enhanced process of consultation with First Nations and Métis communities. As a result of the then Minister of Energy and Infrastructure's directive, the OEB adjourned its review of the IPSP on October 2, 2008.

On May 14, 2009, the GEA was passed in the Ontario Legislature. On September 21, 2009, to support the GEA and help bring renewable energy to the grid, our company received a letter from the then Minister of Energy and Infrastructure requesting us to immediately proceed with the planning and implementation of 20 major transmission projects. On May 7, 2010, the then Minister of Energy and Infrastructure requested that our company focus on those items that are essential to the safe and reliable operation of our existing assets or projects already under development and approved by the OEB, or that are critical to the connection of renewable generation projects that have been identified by the OPA as part of the Province's green energy agenda. As a result, we decided to suspend our work on the 20 major transmission projects. On August 26, 2010, the OEB released its new policy on the Framework for Transmission Project Development Plans. This policy sets out a framework for new transmission investment in Ontario by introducing competition for transmission development through an open process. On March 29, 2011, the Minister of Energy expressed the Province's interest in the OEB commencing a designation process for the East-West Tie Line. The proposed route is a 400 km, 230 kV double-circuit line to run beside an existing Hydro One Networks Inc. (Hydro One Networks) transmission corridor along the north shore of Lake Superior between Hydro One Networks' transformer stations at Wawa in the east and Lakehead in the west. The target in-service date, set by the OPA in its report issued June 30, 2011, is 2017. The East-West Tie LP, an equally-shared partnership of three entities including Hydro One, is currently seeking a transmission licence to participate in the East-West Tie bid process. There are six other potential bidders that are interested in this project. The OEB convened a series of meetings with all potential bidders, the OPA, the IESO and incumbent transmitters in January and February 2012, to discuss the specifics of the process. On February 2, 2012, the OEB issued a Notice of Proceeding, inviting all registered transmitters to file a development plan. The date for filing of plans will be set in due course.

An amendment to the deemed licence conditions of the *Ontario Energy Board Act, 1998*, as set out in the GEA, requires that distributors provide priority connection access for qualified renewable energy generation facilities and prepare plans to be approved by the OEB that identify expansion or reinforcement of the distribution system to accommodate the connection of renewable energy generation facilities.

The OPA continues to procure new, cleaner and renewable generation in Ontario. On October 1, 2009, the OPA launched the Feed-in-Tariff (FIT) Program in accordance with the directive issued to it by the then Minister of Energy and Infrastructure. The program is designed to procure energy from a wide range of renewable energy sources, including wind, solar, photovoltaic, bio-energy and waterpower up to 50 MW. On October 31, 2011, the Ministry of Energy announced the commencement of the planned review of the FIT Program. The review will consider a range of issues including a FIT price reduction. New prices for FIT contracts will be carefully developed to balance the interests of ratepayers with the need to encourage investments in new clean energy. The review will not affect FIT contracts in existence prior to October 31, 2011. All other applications will be subject to the new rules and pricing schedule once the FIT Program review is complete. The review provided an opportunity for feedback and written submissions until December 14, 2011. We submitted comments and participated in the review process in a number of forums.

On November 23, 2010, the Ministry of Energy released Ontario's LTEP which sets out the province's expected electricity needs until 2030 and supports the continued procurement of new, cleaner generation. The LTEP addresses seven key areas: demand, supply, conservation, transmission, aboriginal communities, capital investments and electricity prices. On February 17, 2011, the Province issued a Supply Mix Directive that requires the OPA to prepare a 20-year IPSP to meet the goals set out in the LTEP. The Supply Mix Directive will form the basis for the new IPSP. On May 9, 2011 the OPA announced that it was beginning consultations to update Ontario's IPSP and issued the *IPSP Planning and Consultation Overview* document. A series of four consultation sessions occurred during the month of May. The OPA asked stakeholders to provide input into the IPSP by June 17, 2011. We submitted our comments on that day. Stakeholder comments will form part of the evidence when the OPA submits the revised IPSP to the OEB for review.

On February 28, 2011, the OEB issued a decision amending Hydro One Networks' transmission licence in accordance with a directive from the Minister of Energy to the OEB. The licence amendment requires Hydro One Networks to develop and either seek approvals for or implement specified transmission projects and upgrades to safely and reliably accommodate additional renewable energy in accordance with recommendations from the OPA. In a letter dated April 7, 2011, the OPA provided the scope and timing to increase short circuit and/or transformer capacity at 10 of 15 transformer stations noted in the licence to accommodate small-scale renewable generation. Alternative solutions have been identified for three of these stations and the recovery of the other seven station

upgrades is restricted (see Future Capital Expenditures). On June 30, 2011, we received a letter from the OPA recommending the scope and timing to reconductor two circuits between Sarnia and London, the West of London Transmission Upgrade Project, to enable the connection of additional renewable generation in the west of London area with a required in-service date of December, 2014. On October 3, 2011, we received a letter from the OPA recommending the scope and timing of the Southwestern Ontario Reactive Compensation Priority Project, formerly the Southwestern Ontario Series Compensation Project. After consideration of the options, the OPA has recommended that we install a Static Var Compensator (SVC) at our Milton Switching Station to increase the capability of the Bruce transmission system. We are awaiting an OPA recommendation regarding the construction of a new transmission line west of the City of London.

Transmission and Distribution System Codes

In 2009, the OEB undertook a review of its codes, rules and guidelines in support of the GEA. On October 20, 2009, the OEB finalized amendments to the Transmission System Code (TSC), and adopted a "hybrid" approach to cost responsibility between transmitters and generators for enabler facilities. Enabler facilities are lines or stations that connect two or more renewable generation facilities to the transmission grid. The hybrid option sees the initial pooling of the costs of enabler lines by the transmitter, with generators paying their pro-rata share, based on generator capacity, when ready to connect. To be eligible for this cost treatment, enabler facilities must meet certain detailed requirements outlined in the TSC.

The amendments to the Distribution System Code (DSC), finalized on October 21, 2009, revised the OEB's approach to assigning cost responsibility between a distributor and a generator for the connection of renewable energy generation facilities. The OEB defined three types of distribution assets associated with the connection of renewable energy generation: connection assets, expansion assets, and renewable enabling improvements. For generators that are connecting directly to a distributor's system, connection asset costs will continue to be borne by generators, while distributors will be required to fund all expansion costs identified in a plan, other generator-requested expansion costs up to a cap of $90,000/MW per project (with the generator paying the rest), and all renewable enabling improvements.

On June 30, 2010, Hydro One Networks, in respect of its Distribution Business, filed an application with the OEB requesting an exemption from certain cost responsibility rules contained in the DSC for distributed generation (DG) projects under the Renewable Energy Standard Offer Program. The application sought to deal with unanticipated costs that arose as a result of the connection of certain renewable generation facilities for generators. These generators applied to connect to our system prior to amendments made to the code on October 21, 2009. Under the rules in force at the time, all costs of connection were assigned to generators and we requested an exemption from those rules to allow for recovery of the unforeseen expenditures from ratepayers. On December 20, 2010, the OEB released its decision approving deferral accounts to capture the expenditures to be brought forward for review and approval at the next cost-of-service application.

On October 11, 2011, the OEB issued its decision pertaining to an application we filed on April 19, 2011 requesting an exemption from the DSC timelines for the connection of micro-embedded generation facilities. Since the inception of the microFIT Program, we have issued over 10,000 Offers to Connect, of which over 7,600 projects have been connected as at December 31, 2011. The exemption was requested to manage the anticipated high volume of micro-embedded generator applications, manage summer construction, new connects and high load periods and make necessary revisions to business processes. The OEB decision increases the timeline for processing indirect connections that require a site assessment from 15 days to 30 days. The OEB also approved amendments to the conditions that must be met before we are required to connect micro-embedded generation facilities to the distribution system. Connections must now be performed within 5 business days from the day on which all applicable service conditions are satisfied, or at such later date as agreed to with the customer. The exemption expires on April 11, 2012. On December 14, 2011, the OEB issued an order requiring us to file our first compliance report by January 3, 2012 and on a monthly basis thereafter, until we have met the DSC requirements for three consecutive months.

CDM

In 2009, the OPA continued to be responsible for coordinating the delivery and funding of CDM programs. This coordination furthered initiatives undertaken by individual LDCs, including the distribution businesses of our subsidiaries Hydro One Networks and Hydro One Brampton Networks Inc. (Hydro One Brampton), as a result of OEB program requirements . Our CDM programs funded through the OPA in 2011 amounted to approximately $15 million, compared to $31 million in 2010. The *Ontario Energy Board Act, 1998*, as amended by the GEA, provides direction to the OEB to take steps to establish CDM targets to be met by LDCs and other licensees. The then Minister of Energy and Infrastructure's March 31, 2010 directive set a province-wide CDM target for Ontario's LDCs. The two key CDM targets for LDCs over the four-year period beginning January 1, 2011 are to reduce 1,330 MW of provincial summer peak demand and 6,000 GWh of cumulative energy savings, collectively.

On June 22, 2010, the OEB provided notice under the *Ontario Energy Board Act, 1998* of the creation of a proposed CDM Code for Electricity Distributors (CDM Code). On the same day it issued proposed specific CDM targets for all LDCs as directed by the then Minister of Energy and Infrastructure earlier that year. The CDM Code was issued by the OEB on September 16, 2010. On November 12, 2010, the OEB issued final CDM targets to each LDC. The allocation of the overall targets to our company are a 259 MW reduction of provincial peak demand and a 1,320 GWh reduction of electricity consumption, representing, respectively, 19.5% and 22.0% of the total target savings established for all LDCs. The CDM Code also set out the conditions and rules that LDCs are required to follow if they choose to use OEB-approved CDM programs to meet their CDM targets. We do not intend to file an application for OEB-approved programs.

The *Energy Conservation Responsibility Act, 2006* furthers the broad objectives of CDM by providing the framework for the installation of smart meters in all homes and small businesses in Ontario by December 31, 2010. These meters are capable of measuring and reporting usage over predetermined periods, being read remotely, and, when combined with communications systems, are capable of providing customers with access to information about their consumption. In 2007, the Province appointed the IESO as the interim smart meter entity that will oversee the collection and management of data. LDCs, including our distribution businesses, are accountable for the deployment of smart meter infrastructure and related technology for communications to meet minimum requirements as defined in regulations, as well as the implementation of TOU rates. In 2010, we continued our focus on building an ADS and launched our initiative to leverage the infrastructure from our earlier smart meter investments. In 2011, we carried out a number of studies on advanced distribution technologies and initiated the Smart Zone Pilot Project in the Owen Sound area. The Smart Zone Pilot consists of testing and demonstrating power system equipment, IT systems and communication systems that will be required to help facilitate the connection of a large number of DG connections to the distribution system. Further releases of the ADS will look at optimizing outage response through more effective dispatch, automation to isolate faults where needed and the dynamic regulation of voltage to reduce losses. All releases leverage a core set of infrastructure and build on each other, and as pilot elements are proven, business cases will be developed for the provincial roll out which will ultimately comprise the ADS.

Renewed Regulatory Framework

On December 17, 2010, the OEB initiated a coordinated consultation process for the development of a renewed regulatory framework for electricity distributors and transmitters. This effort is intended to help ensure the reliable and cost-effective delivery of electricity to Ontario consumers in light of the significant anticipated investment needed for the renewal of existing assets and to connect new generation.

On November 8, 2011, the OEB released five staff discussion papers and supporting consulting reports that are intended to initiate dialogue with stakeholders. These papers and reports looked at many issues including: distribution network investment planning; regional planning; smart grid (our version is ADS); rate mitigation/smoothing; and performance measurement. The anticipated outcome of this initiative is a regulatory framework with several potential areas of change including rate design, system codes, cost allocation, cost responsibility, reporting requirements and a performance measurement matrix.

Transmission Rates

The IESO facilitates payments to us based on the Ontario Uniform Transmission Rates (UTRs) approved by the OEB for all transmitters across Ontario.

To achieve the necessary funding in support of aging critical infrastructure and investments, we submitted a transmission rate application for 2009 and 2010 rates in September 2008. The application sought OEB approval for revenue requirements of approximately $1,233 million and $1,341 million based on returns on equity (ROE) of 8.53% and 9.35% for 2009 and 2010, respectively. On May 28, 2009, the OEB issued its decision, effective July 1, 2009, which resulted in a reduced revenue requirement of $1,180 million and $1,240 million in 2009 and 2010, respectively, primarily due to lower approved ROEs of 8.01% and 8.16%. The decision also required the establishment of new regulatory accounts to track the difference between the forecasted and actual external revenues for export services, secondary land use and net maintenance services provided primarily to generators. In its decision, the OEB disallowed development capital expenditures of $180 million in 2010, but agreed to reconsider the projects if additional evidence was provided. On September 4, 2009, we filed supplemental evidence regarding two of the development capital projects amounting to approximately $160 million. On December 11, 2009, the OEB issued its final report on its cost-of-capital review that concluded that the formula-based ROE needed to be reset and refined. On December 16, 2009, the OEB approved our supplemental submission increasing the approved 2010 revenue requirement to $1,257 million on the basis of an updated 2010 ROE of 8.39%. These decisions resulted in an increase in transmission tariff rates of approximately 2% and 9% for 2009 and 2010, respectively, representing a less than 1% increase on an average customer's total bill in each year.

On May 19, 2010 we submitted an application for 2011 and 2012 transmission rates in continued support of our aging critical infrastructure and supply mix objectives for generation, including off-coal initiatives and initiation of investments in support of the GEA. This application sought the approval of revenue requirements of approximately $1,446 million for 2011 and $1,547 million for 2012, which represented estimated rate increases of 15.7% and 9.8%, respectively, or 1.2% and 0.7% on an average customer's monthly bill. The application was filed using the new OEB-approved formula for ROE and took into consideration the OEB staff report on the regulatory treatment of infrastructure investment in connection with rate-regulated activities of Ontario distributors and transmitters, issued in January, 2009.

On December 23, 2010, the OEB issued its decision, which resulted in a revenue requirement effective January 1, 2011 of $1,346 million for 2011 and $1,658 million for 2012, reflecting transmission rate changes of approximately 7% in 2011 and 26% in 2012, or 0.5% and 2%, respectively on an average customer's total bill. The 2011 revenue requirement was lower than requested primarily due to a lower prescribed ROE resulting from a lower forecasted cost of debt, the denial of our request to recover the cost of capital on the construction work-in-progress for our Bruce to Milton Transmission Reinforcement Project and an envelope OM&A reduction. Our 2012 revenue requirement was also impacted by the above-noted factors, but was higher than we originally submitted due to the OEB directing us to adopt a capitalization policy that was consistent with modified International Financial Reporting Standards (IFRS). This specific revision resulted in an increased revenue requirement of about $200 million for 2012.

On January 17, 2011, the Power Workers Union (PWU) submitted an appeal of the decision to the Ontario Superior Court of Justice (Divisional Court) asserting that the OEB failed to permit our company to recover proposed prudently incurred OM&A costs and therefore, that a legal error was made. The appeal has not affected the collection of the 2011 transmission rates. The appeal in this matter was heard by the Divisional Court in October, 2011. A decision is currently pending.

Consistent with our approval from the Ontario Securities Commission (OSC) to adopt United States (US) Generally Accepted Accounting Principles (GAAP) for external financial reporting and securities filings, on July 15, 2011 we filed a Motion to Vary the OEB's 2012 rate decision. Our application sought approval to adopt US GAAP as a basis for regulatory accounting and rate setting in place of the OEB's approved modified IFRS basis. The adoption of US GAAP in lieu of modified IFRS decreases the 2012 revenue requirement by the same $200 million adjustment that was made by the OEB in its 2012 decision.

In response to our Motion to Vary, the OEB on its own motion held a written proceeding to review our request to adopt US GAAP for rate-setting purposes. On November 23, 2011, the OEB issued its decision with reasons that approved the use of US GAAP by our Transmission Business. The decision also approved adjustments to our 2012 transmission revenue requirement, capital expenditures and rate base consistent with those we proposed in our evidence. The OEB also approved creation of several new US GAAP regulatory accounts.

On December 1, 2011, we submitted to the OEB a draft 2012 transmission revenue requirement that reflects the approved adoption of US GAAP for rate-setting purposes as well as the OEB-directed update to 2012 cost-of-capital parameters. On December 20, 2011, the proposed $1,418 million 2012 revenue requirement was approved by the OEB along with new 2012 UTRs effective January 1, 2012. The new rates result in an approximate 8% transmission rate increase, or 0.6% on an average customer's total bill. The adoption of US GAAP in lieu of modified IFRS has decreased the revenue requirement in 2012 by approximately $200 million and decreased the approved rates by 15%.

Distribution Rates

As a distributor, we are responsible for delivering electricity and billing our customers for our approved distribution rates, purchased power costs and other approved regulatory charges. Substantially all of our purchased power costs and other approved regulatory charges are settled through the IESO, which facilitates payments to other parties such as generators, the Ontario Electricity Financial Corporation (OEFC) and the IESO itself.

In 2006, the OEB established a multi-year electricity distribution rate-setting plan whereby a distributor's rates are set via a cost-of-service rebasing application in one of the years 2008, 2009, 2010 or 2011. Following the year of rebasing, a distributor would be subject to an Incentive Regulation Mechanism (IRM) that uses a formulaic approach to establish rates for the next three years. The third-generation IRM plan currently in effect establishes a pre-defined set of conditions under which the IRM plan could be terminated allowing for a utility to file a cost-of-service application.

Hydro One Networks

On July 13, 2009, we filed a cost-of-service application with the OEB for 2010 and 2011 distribution rates reflecting our plan to invest in our network assets to meet objectives regarding public and employee safety; regulatory and legislative compliance; maintenance of system security and reliability of system growth requirements; and investments required by the GEA. An updated application was filed on September 25, 2009. The revised application sought OEB approval of revenue requirements of approximately $1,150 million and $1,264 million based on ROEs of 8.11% and 9.09% for 2010 and 2011, respectively. The resulting distribution tariff rate increase was approximately 10% and 13% in 2010 and 2011, respectively, or approximately 3% and 4% on an average customer's total bill.

Our application included the Green Energy Plan (GEP) for our Distribution Business, filed in response to the GEA, which directed the OEB to require transmitters and distributors to file plans that would lead to the expansion of their systems to facilitate renewable energy. Our plans identified the expansion and reinforcement of the distribution system required to accommodate the connection of renewable energy generation facilities and outlined the development and implementation of an ADS. Our GEP reflected changes to the *Ontario Energy Board Act, 1998*, as amended by the GEA and stipulated in Ontario Regulation 330/09. The amendments provided a new mechanism for rate protection, whereby some or all of the OEB-approved costs incurred by a distributor to make an eligible investment for the purpose of connecting or enabling the connection of renewable energy generation to its distribution system may be recovered from all provincial ratepayers, rather than solely from ratepayers of the distributor making the investment.

On April 9, 2010, the OEB released its decision approving revenue requirements of $1,146 million for 2010 and $1,236 million for 2011 to support the necessary work programs, the implementation of the GEA and the installation of smart meters. The 2010 and 2011 revenue requirements were lower than originally requested, reflecting reductions in our requested OM&A expenses, capital expenditures and working capital requirements. As part of its decision, the OEB also approved disposition of certain distribution-related regulatory account balances we sought in our application, including retail settlement variance accounts, the remainder of a regulatory asset recovery account, retail cost variance accounts and smart meters. The OEB ordered that the approved balances be aggregated into a

single regulatory account to be recovered over an 18-month period from May 1, 2010 to December 31, 2011. Further, the OEB requested the establishment of new regulatory accounts to track the difference between the revenue recorded on the basis of our GEP expenditures incurred and actual recoveries received under the approved funding adder. These differences are tracked in the regulatory account we refer to as Rider 8.

The 2010 distribution rates were implemented on May 1, 2010, reflecting a rate increase of approximately 9.3%, or approximately 3% on an average customer's total bill. Our 2011 revenue requirement was adjusted to reflect the OEB's decision to decrease OM&A by $40 million and was also adjusted to reflect a $44 million capital program reduction. On November 15, 2010, the OEB issued its cost-of-capital parameter updates for rates effective January 1, 2011. The new ROE value for 2011 is 9.66%. Applying this lower ROE produced a revised revenue requirement of $1,218 million. The approved 2011 revenue requirement resulted in an average distribution rate increase of approximately 8.7% for 2011, or 3.0% on an average customer's total bill.

Given the close relationship between Hydro One Networks' transmission and distribution businesses, we originally included a request to allow our Distribution Business to adopt US GAAP for rate-setting purposes as part of our Transmission US GAAP application. In its November 23, 2011 Transmission Business decision, the OEB determined that it would not make a decision on the Distribution portion of our request for procedural reasons but did indicate that it would consider a stand-alone application requesting the extension of the use of US GAAP to our Distribution Business. On December 1, 2011 we submitted our application requesting that the OEB approve the use of US GAAP in place of modified IFRS for rate-setting purposes within our Distribution Business effective January 1, 2012. In our application, we estimated that a 2012 notional Hydro One Distribution revenue requirement would be $166 million higher under modified IFRS compared to US GAAP, primarily due to differences in capitalization policy. We also indicated that we are not requesting any change to our approved distribution rates at this time. A decision on our request to adopt US GAAP for our Distribution Business is anticipated in the first quarter of 2012.

Hydro One Brampton

On November 7, 2008, our subsidiary Hydro One Brampton filed an application for 2009 rates on the basis of the OEB's second-generation IRM policy. This incorporates an OEB-approved formula that considers inflation and efficiency targets. On March 13, 2009, the OEB issued its decision with reasons and revised rates, including an amount of $1 per month per metered customer for smart meters, were approved for implementation effective May 1, 2009. Overall, the impact on an average customer's total bill was marginal.

On November 6, 2009, an application for 2010 distribution rates was filed on the basis of the OEB's second-generation IRM process. On April 13, 2010, the OEB released its decision regarding this rate application approving our submission on the basis of the OEB's cost-of-capital and second-generation IRM policies. The revised rates were implemented on May 1, 2010 and resulted in a reduction of approximately 8.3%, or 2.2% on an average customer's total bill in the year.

On June 30, 2010, we submitted a 2011 cost-of-service application, which was subsequently adjusted on September 2, 2010 to reflect the deferral of the adoption of modified IFRS until January 1, 2012. The updated submission was filed on November 8, 2010 and requested OEB approval for a revenue requirement of approximately $63 million. On April 4, 2011, the OEB issued a decision with reasons that reduced the requested revenue requirement. This reduction included the impact of reductions to OM&A costs. The revised rates were approved with an effective date of January 1, 2011 and an implementation date of May 1, 2011. Included in the rates is an amount of $1.52 per month per metered customer for smart meters and approval of a GEA funding adder of $0.02 per month per metered customer. The new rates result in a total bill increase for an average customer of approximately 0.5%.

On September 15, 2011, Hydro One Brampton filed an application for 2012 rates on the basis of the OEB's third-generation IRM process. In its application, it requested recovery of lost revenues associated with load reduction related to energy conservation programs. Hydro One Brampton requested approval for a Lost Revenue Adjustment Mechanism and disposal of the provision for payments in lieu of corporate income taxes (PILs) regulatory account balance. On December 22, 2011, the OEB issued its decision on the application, directing Hydro One Brampton to file a draft Rate Order by December 30, 2011. The draft Rate Order was filed on December 28, 2011 and on December 31, 2011, the OEB declared Hydro One Brampton's existing rates interim as of January 1, 2011. On January 5, 2012, the OEB released a decision with reasons that resulted in a reduction in rates of approximately 13.2%, or a 1.7% reduction on the average customer's total bill in the year. These rate reductions were primarily due to OEB-approved adjustments to existing depreciation rates.

Hydro One Remote Communities Inc. (Hydro One Remote Communities)

On November 4, 2009, our subsidiary Hydro One Remote Communities filed its application for 2010 rates under the OEB's third-generation IRM. This application sought OEB approval for an increase to basic rates for the distribution and generation of electricity effective May 1, 2010. The requested rate increase reflected the standard inflationary adjustments incorporated in third-generation IRM applications. On April 14, 2010, the OEB issued a decision with reasons regarding this rate application. Revised rates were approved for implementation effective May 1, 2010 and reflected an increase of approximately 0.4%, for which the overall impact on an average customer's total bill was marginal.

On October 15, 2010, an application for 2011 distribution rates was filed on the basis of the OEB's third-generation IRM seeking approval for an increase of approximately 0.4% to basic rates for the distribution and generation of electricity effective May 1, 2011. On March 28, 2011, the OEB issued its decision approving the application with an effective date and implementation date for the new rates of May 1, 2011. The overall impact of the new rates on an average residential customer's total bill was marginal.

On November 25, 2011, we filed an application for 2012 distribution rates on the basis of the OEB's third-generation IRM seeking approval for an increase of approximately 0.4% to basic rates for the distribution and generation of electricity effective May 1, 2012. We expect to update our rate application when the OEB issues its inflation and productivity factors for IRM filers in the first quarter of 2012.

Consistent with the OEB's decision affirming the use of US GAAP for rate-setting purposes by Hydro One Networks' Transmission Business, on December 15, 2011, we made a similar request to use US GAAP for Hydro One Remote Communities. We anticipate a decision in the first quarter of 2012.

RESULTS OF OPERATIONS

Revenues

Year ended December 31 (Canadian dollars in millions)	2011	2010	$ Change	% Change
Transmission	1,389	1,307	82	6
Distribution	4,019	3,754	265	7
Other	63	63	-	-
	5,471	5,124	347	7
Average annual Ontario 60-minute peak demand *(MW)*[1]	21,166	21,572	(406)	(2)
Distribution – units distributed to customers *(TWh)*[1]	29.2	29.1	0.1	-

[1] System-related statistics include preliminary figures for December.

Transmission

Transmission revenues predominantly consist of our transmission tariff, which is based on the monthly peak demand for electricity across our high-voltage network. The tariff is designed to recover revenues necessary to support a transmission system with sufficient capacity to accommodate the maximum expected demand. Demand is influenced by weather and economic conditions. Transmission revenues also include minor amounts of ancillary revenues which are primarily attributable to maintenance services provided to generators and to secondary use of our land rights-of-way.

Our transmission revenues were higher by $82 million, or 6%, compared to 2010. This increase was primarily due to higher tariff revenues of $87 million resulting from a December 23, 2010 OEB decision on the 2011 and 2012 transmission rate application by our subsidiary, Hydro One Networks, consistent with our allowed ROE. The decision followed extensive oral and written reviews of evidence we submitted for the funding necessary to support our system requirements. The resulting rates, which were effective January 1, 2011, support our investments to address aging critical infrastructure, supply mix objectives for generation including off-coal initiatives, and the initiation of investments in support of the GEA. Ancillary revenue for the year was higher by $16 million than in 2010 due to increased external revenues. We also experienced higher export service revenue of $4 million,

compared to the prior year. Export service and external amounts received in excess of approved levels are recorded in a regulatory account.

Revenues for the year also reflect lower average peak demands compared to last year, resulting in a decrease in transmission revenue of $13 million. The average annual Ontario 60-minute peak demand and the overall related load were 406 MW and 4,866 MW lower than last year, respectively. Among other factors, we experienced milder weather in the third and fourth quarters, compared to 2010.
We also experienced lower transmission revenues associated with OEB-approved regulatory accounts of $12 million compared to last year, mainly related to the full recovery of a transmission regulatory account at the end of last year.

Distribution

Distribution revenues include our distribution tariff, as well as amounts to recover the cost of purchased power used by our customers. Accordingly, our distribution revenues are influenced by the amount of electricity we distribute, the cost of purchased power and our approved distribution tariffs. Distribution revenues also include a minor amount of ancillary distribution services revenues, such as fees related to the use of our poles by the telecommunications and cable television industries, and miscellaneous charges such as those for late payments.

Distribution revenues increased by $265 million, or 7%, compared to 2010. After excluding higher purchased power costs of $154 million, as described below in the section Purchased Power, the increase was $111 million, or 9%.

After considering purchased power costs, increases in revenue reflect two OEB decisions on the distribution tariff rates of our subsidiary, Hydro One Networks. On April 9, 2010, the OEB approved new tariff rates effective May 1, 2010 and on December 21, 2010, the OEB approved new tariff rates effective January 1, 2011, consistent with our allowed ROE. Both OEB decisions followed extensive written and oral reviews of the evidence we submitted for the maintenance and investment requirements of our distribution system. The combined impact of these decisions was an increase in distribution revenues of $93 million. These tariff rate increases enable the safe and reliable delivery of electricity to our customers throughout Ontario and begin the development of the ADS to ensure the future integrity of our system as we connect large volumes of new DG. In addition, we experienced higher smart meter revenues of $18 million during the year, reflecting the recovery of our increased expenditures incurred consistent with higher levels of in-service smart meter assets. We have met the OEB requirements for smart meters and the transition to TOU and continue to work with the IESO on enhanced systems functionality.

Higher energy consumption, resulting primarily from the colder winter at the beginning of this year, increased our distribution revenues by a further $6 million. We also experienced increased other revenues of $2 million for the year. Distribution revenue increases were partially offset by a revenue reduction of $8 million compared to the prior year associated with the full recovery of a distribution-related regulatory account effective April 30, 2010.

Purchased Power

Purchased power costs incurred by our Distribution Business represent the cost of electricity delivered to customers within our distribution service territory and comprise the wholesale commodity cost of energy, the IESO's wholesale market service charges, and transmission charges levied by the IESO. The commodity cost of energy for certain low-volume and designated customers is based on the OEB's RPP, which consists of a two-tiered pricing structure with threshold amounts and a separate pricing structure for RPP customers on TOU billing, both of which are adjusted twice annually. We began transitioning our RPP customers to TOU billing May 1, 2010 and, as noted, the majority of our RPP customers are now on TOU billing. Customers who are not eligible for the RPP pay the market price for electricity, adjusted for the difference between market prices and the prices paid to generators under the *Electricity Restructuring Act, 2004*. A summary of the RPP for the reporting and comparative periods is provided below.

Summary of RPP

	Tier Threshold (kWh/month)		Tier Rates (cents/kWh)	
Effective Date	**Residential**	**Non-Residential**	**First Tier**	**Second Tier**
November 1, 2009	1,000	750	5.8	6.7
May 1, 2010	600	750	6.5	7.5
November 1, 2010	1,000	750	6.4	7.4
May 1, 2011	600	750	6.8	7.9
November 1, 2011	1,000	750	7.1	8.3

RPP TOU	Rates (cents/kWh)		
Effective Date	**On Peak**	**Mid Peak**	**Off Peak**
May 1, 2010	9.9	8.0	5.3
November 1, 2010	9.9	8.1	5.1
May 1, 2011	10.7	8.9	5.9
November 1, 2011	10.8	9.2	6.2

Purchased power costs increased in 2011 by $154 million, or 6%, to $2,628 million for the year compared to 2010. The increase in our purchased power costs was primarily due to: the impact of changes in the OEB's RPP rates for residential and other eligible customers of $75 million; higher purchased power costs of $56 million for customers who are not eligible for the RPP; increased transmission charges of $24 million due to the OEB's transmission rate decision effective January 1, 2011; and the impact of higher demand for electricity of $2 million. The effect of these increases was partially offset by lower charges levied by the IESO of $3 million.

OM&A

Our OM&A costs consist of labour, material, equipment and purchased services which support the operation and maintenance of the transmission and distribution systems. Also included in these costs are property taxes and payments in lieu thereof on our transmission and distribution lines, stations and buildings.

OM&A costs for each of our three business segments were as follows:

Year ended December 31 (Canadian dollars in millions)	**2011**	**2010**	**$ Change**	**% Change**
Transmission	422	416	6	1
Distribution	609	602	7	1
Other	61	60	1	2
	1,092	1,078	14	1

Transmission

OM&A expenditures incurred to sustain our high-voltage transmission stations, lines and rights-of-way increased by $6 million, or 1%, in 2011 compared to last year. Within our work programs, we continued to invest in the safe and reliable operation of our transmission system that spans Ontario. Our work program requirements were higher by $39 million compared to last year. During the year, we incurred expenditures of $19 million related to the OPA's recommendation to increase short circuit and/or transformer capacity at 10 of our transmission stations to enable the connection of small renewable projects, for which recovery is restricted (see Future Capital Expenditures). In addition, we experienced higher requirements for station maintenance for power equipment, maintenance to repair aging underground cables and higher requirements related to the fire at our Richview Transformer Station. Our crews worked tirelessly to rebuild and place in-service the impacted aging transformers to ensure adequate supply to critical LDCs. We also experienced higher requirements for our forestry program. Our expenditures in support of our transmission system have decreased by $33 million reflecting lower telecom expenditures from lower long distance rates associated with leveraging broader public sector rates on voice domain, lower data usage and lower support costs. Also, we made an additional contribution of $27 million to our pension plan in the last quarter of 2010.

Distribution

OM&A expenditures required to maintain our low-voltage distribution system increased by $7 million, or 1%, compared to last year. Our work program expenditures increased by $16 million primarily related to increased power restoration expenditures as the province experienced a higher volume of storm activity, as well as increased requirements associated with unplanned system changes to implement OEB code amendments impacting our billing system. This was partially offset by lower expenditures for our line patrol program as a result of new data collection methods, lower field meter reading expenditures and a lower forestry program this year. Our expenditures in support of our distribution system decreased by $9 million, reflecting lower telecom costs and other support costs. We also made an additional contribution to our pension plan of $21 million in the last quarter of 2010. These costs were partly offset by a redirection of resources in support of DG programs.

Depreciation and Amortization

Depreciation and amortization expense increased by $33 million, or 6%, to $616 million in 2011 compared to the prior year. The increase was mainly attributable to higher depreciation of approximately $29 million related to the placement of new assets in service, consistent with our ongoing capital work program. We also experienced an increase of $9 million as a result of an increase in fixed asset removal costs associated with storm restoration and fire restoration work during the year. Amortization of regulatory and other assets decreased by $6 million, mainly due to the full recovery of a distribution regulatory account during the second quarter of last year.

Financing Charges

Financing charges increased by $2 million, or 1%, to $344 million for 2011 compared to 2010. The increase is mainly due to a $9 million increase in long-term debt interest expense primarily as a result of an increased average level of debt, partially offset by a lower average effective interest rate. This increase was partially offset by higher interest capitalized of $3 million reflecting higher levels of construction-in-progress consistent with our growing capital program and favourable changes in interest income and other ancillary amounts which reduced overall financing charges by $4 million.

Provision for Payments in Lieu of Corporate Income Taxes

We make PILs to the OEFC in accordance with the *Electricity Act, 1998* and on the same basis as if we were subject to federal and provincial corporate taxes. In providing for PILs, the liability method is used. The change in future taxes relating to both the unregulated and regulated businesses, in respect of temporary differences that are not considered for the rate-setting process, results in a future tax provision that is charged to the Consolidated Statement of Operations. The change in future taxes relating to temporary differences of the regulated businesses that are considered for the rate-setting process results in a regulatory asset or regulatory liability.

The provision for PILs increased by $94 million, or 168%, to $150 million compared to 2010. The increase was primarily due to changes in net temporary differences, including lower capital cost allowance claimed on software than in the prior year, and higher pre-tax income in the year. Net increases in 2011 were partially offset by a reduction in the statutory tax rate from 31.00% to 28.25%.

Net Income

Net income of $641 million was higher than our comparable 2010 results by $50 million, or 8%. Net income reflects OEB rate decisions that allowed for, among other things, the recovery of capital investments from prior years that are now in-service. New assets in service include investments to address our aging critical infrastructure and the supply mix objectives for generation, including off-coal initiatives, and investments in support of the GEA. Higher revenues were partially offset by higher operating expenditures, including those related to our non-recoverable work to increase short circuit and/or transformer capacity at some of our transmission stations to enable the connection of small renewable projects, and by a higher effective tax rate.

Quarterly Results of Operations

The following table sets forth unaudited quarterly information for each of the eight quarters from March 31, 2010 through December 31, 2011. This information is derived from our unaudited interim Consolidated Financial Statements which, in the opinion of our management, have been prepared on a basis consistent with the audited

annual Consolidated Financial Statements and which include all adjustments, consisting only of normal recurring adjustments, necessary for fair presentation of our financial position and results of operations for those periods. These operating results are not necessarily indicative of results for any future period and should not be relied upon to predict our future performance.

(Canadian dollars in millions)	2011				2010			
Quarter ended	**Dec. 31**	**Sep. 30**	**Jun. 30**	**Mar. 31**	**Dec. 31**	**Sep. 30**	**Jun. 30**	**Mar. 31**
Total revenues[1]	1,359	1,384	1,268	1,460	1,280	1,360	1,165	1,319
Net income[1]	120	167	142	212	99	218	105	169
Net income to common shareholder[1]	115	163	137	208	94	214	100	165

[1] The demand for electricity generally follows normal weather-related variations, and therefore our electricity-related revenues and profit, all other things being equal, would tend to be higher in the first and third quarters than in the second and fourth quarters.

LIQUIDITY AND CAPITAL RESOURCES

Our primary sources of liquidity and capital resources are funds generated from operations, debt capital market borrowings and bank financing. These resources will be used to satisfy our capital resource requirements, which continue to include capital expenditures, servicing and repayment of our debt, payments related to our outsourcing arrangements, other investing activities, and dividends.

Summary of Sources and Uses of Cash

Year ended December 31 (Canadian dollars in millions)	**2011**	**2010**
Operating activities	1,407	1,164
Financing activities		
Long-term debt issued	700	1,500
Long-term debt retired	(500)	(600)
Short-term notes payable	-	(55)
Dividends paid	(168)	(28)
Investing activities		
Capital expenditures	(1,447)	(1,570)
Long-term investments[1]	-	(250)
Other financing and investing activities	28	37
Net change in cash and cash equivalents	17	198

[1] Represents $250 million of Province of Ontario Floating Rate Notes.

Operating Activities

Net cash from operating activities increased by $243 million to $1,407 million in the year, compared to 2010. The increase primarily reflects higher net income this year combined with the impact of changes in accounts payable balances related to the timing of customer prepayments and advances for engineering work, increases in taxes payable resulting from required levels of in-year tax installments and changes in certain regulatory account balances.

Financing Activities

Short-term liquidity is provided through funds from operations, our Commercial Paper Program under which we are authorized to issue up to $1,000 million in short-term notes with a term to maturity of less than 365 days, our revolving credit facility and through our holding of Province of Ontario Floating Rate Notes.

The Commercial Paper Program is supported by a total of $1,500 million in liquidity facilities comprised of our $1,250 million committed revolving credit facility with a syndicate of banks maturing in June 2014 and our holding of $250 million of Province of Ontario Floating Rate Notes. The short-term liquidity under this program and anticipated levels of funds from operations should be sufficient to fund our normal operating requirements.

As at December 31, 2011, we had $7,975 million in long-term debt outstanding, including the current portion. Our notes and debentures mature between 2012 and 2051. Long-term financing is provided by our access to the debt markets, primarily through our Medium-Term Note (MTN) Program. On August 23, 2011, we filed a base shelf prospectus to renew our MTN Program for another 25 months. The maximum authorized principal amount of medium-term notes issuable under this program is $3,000 million. As at December 31, 2011, $2,600 million remains available until September 2013.

	Rating	
Rating Agency	**Short-term Debt**	**Long-term Debt**
DBRS Limited	R-1 (middle)	A (high)
Moody's Investors Service Inc.	Prime-1	Aa3
S&P	A-1	A+

We have the customary covenants normally associated with long-term debt. Among other things, our long-term debt covenants limit our permissible debt as a percentage of our total capitalization, limit our ability to sell assets and impose a negative pledge provision, subject to customary exceptions. The credit agreements related to our credit facilities have no material adverse change clauses that could trigger default. However, the credit agreements require that we provide notice to the lenders of any material adverse change within three business days of the occurrence. The agreements also provide limitations that debt cannot exceed 75% of total capitalization and that debt issued by our subsidiaries cannot exceed 10% of the total book value of our assets. We are in compliance with all these covenants and limitations as at December 31, 2011.

In 2011, we successfully issued $700 million in cost-effective long-term debt under our MTN Program, consisting of $300 million in the first quarter, $300 million in the third quarter and $100 million in the fourth quarter. We also repaid $500 million in maturing long-term debt, $250 million in the first quarter and $250 million in the fourth quarter. In 2010, we issued $1,500 million in long-term debt under our MTN Program, $1,000 million in the first quarter and $500 million in the third quarter, and repaid $600 million in maturing long-term debt, $400 million in the second quarter and $200 million in the fourth quarter. In 2011, we did not issue any short-term notes. In 2010, we reduced our short-term notes by $55 million, all in the first quarter, and there were no short-term notes outstanding as at December 31, 2010.

Common dividends are declared at the sole discretion of our Board of Directors, and are recommended by management based on results of operations, maintenance of the deemed regulatory capital structure, financial condition, cash requirements, and other relevant factors such as industry practice and shareholder expectations. Common dividends pertaining to the quarterly financial results are generally declared and paid in the immediately following quarter.

In 2011, we paid dividends to the Province in the amount of $168 million, consisting of $150 million in common dividends and $18 million in preferred dividends. In the comparative period, we paid common dividends of $10 million and preferred dividends of $18 million. In 2011, cash dividends per common share were $1.500 compared to $100 per common share in 2010. Cash dividends per preferred share were $1.375 in each of 2011 and 2010.

On February 10, 2012, we declared dividends to the Province in the amount of $281 million, consisting of $277 million in common dividends and $4 million in preferred dividends.

Our objectives with respect to our capital structure are to maintain effective access to capital on a long-term basis at reasonable rates, and to deliver appropriate financial returns. In order to ensure ongoing effective access to capital, we target an "A" category long-term credit rating.

Investing Activities

Cash used for investing activities, primarily representing capital expenditures to enhance and reinforce our transmission and distribution infrastructure in the public interest, was as follows:

Year ended December 31 (Canadian dollars in millions)	2011	2010	$ Change	% Change
Transmission	810	936	(126)	13
Distribution	628	629	(1)	-
Other	9	5	4	80
	1,447	1,570	(123)	8

Transmission

Transmission capital expenditures decreased by $126 million in 2011 to $810 million, compared to 2010. Expenditures to expand and reinforce our transmission system were $416 million, representing a decrease of $108 million from last year. The majority of our expenditures were made on inter-area network projects to support the Province's supply mix objectives for generation, although we continue to make significant investments on load customer connection and local area supply projects to address growing loads. The year-over-year reduction in our expenditures results from projects that were in their final stages of completion this year. These projects included the installation of complex SVCs at our Nanticoke and Detweiler transformer stations and at our Porcupine and Kirkland Lake transformer stations. We also experienced lower expenditures compared to 2010 due to major inter-area network projects completed and put into service last year, including the installation of capacitor banks in Southwestern Ontario and our Cherrywood Transformer Station to Claireville Transformer Station Connection Project. Local area supply projects that were substantially completed last year included our Greater Toronto Area (GTA) West Transmission Reinforcement Project and our Hurontario Transformer Station to Jim Yarrow Municipal Transformer Station connection. The impact of the reduction in expenditures was partially offset by an increase in our investments this year in a number of load customer connection projects.

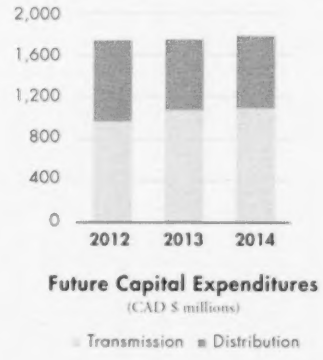
Inter-area network upgrades with significant expenditures this year included our Bruce to Milton Transmission Reinforcement Project to connect refurbished nuclear and new wind generation sources in the Huron-Grey-Bruce area. In the fourth quarter, our SVCs at our Nanticoke and Detweiler transformer stations went into service. In the short term, this project supports increased generation from the Bruce Nuclear facility and in the longer term it will enhance the transfer capability between Southwestern Ontario and the GTA. We also installed the SVC at our Kirkland Lake Transformer Station as part of our project to install SVCs at our Porcupine and Kirkland Lake transformer stations. The SVC at our Porcupine Transformer Station went into service late in 2010. This project increases the North-South interface transfer capability to access available northern generation.

Our local area supply project expenditures include investments in our Woodstock Area Transmission Reinforcement Project to increase capacity and ensure supply reliability in the Woodstock area and the Switchyard Reconstruction Project at our Burlington Transformer Station, which will address aging infrastructure and increase the load supply capacity to ensure reliability of supply to customers in the area. During the year, we also commenced work on our Midtown Electricity Infrastructure Renewal project (formerly the Midtown Toronto Project), together with Toronto Hydro-Electric System Limited, to replace aging cable and overhead line facilities and to provide additional supply capability to meet future load growth in midtown Toronto as well as areas to the west.

Expenditures to sustain our existing transmission system were $335 million, representing a decrease of $23 million compared to 2010. The reduction was primarily related to lower expenditures to enhance security infrastructure related to the prevention of copper theft, as work was substantially completed in the year, as well as lower expenditures for work on our protection and control systems compared to the prior year due to a re-allocation of resources to development projects. We also incurred lower expenditures related to the strategic purchase of power transformers compared to the prior year. In order to ensure transmission reliability, purchases were made in 2010 for these critical long delivery lead-time items. These reductions were partially offset by increased requirements related to the refurbishment and replacement of end-of-life lines and stations. Our other transmission capital expenditures were $59 million, representing an increase of $5 million compared to the prior year. The majority of these expenditures were related to our fleet and to IT development.

Distribution

Distribution capital expenditures decreased marginally by $1 million to $628 million in 2011, compared to the prior year. Capital expenditures to expand and reinforce our distribution network were $269 million, representing a reduction of $68 million compared to last year. We experienced reductions related to the substantial completion of smart meter installations by the end of 2010, and lower expenditures in our wholesale metering program. During the year, we continued to invest in our smart meter network infrastructure and the development and integration of the systems required for TOU billing, including meter reading capability and integration with the IESO meter data repository. Of our 1.3 million customers with smart meters installed as at December 31, 2011, we had over 1.1 million consuming power based on TOU pricing. We also continued to invest in our ADS Project that will enhance our operations and support DG.



Expenditures to sustain our distribution system were $240 million, an increase of $34 million from 2010. During the year, we experienced increased requirements for emergency restoration work as a result of a higher number of storms, including two major storms that hit Ontario in the second quarter. Partially offsetting these impacts were lower expenditures related to reduced work for joint use and relocation of our lines.

Our other distribution capital expenditures were $119 million, representing an increase of $33 million from 2010. This increase is primarily attributable to expenditures for the next phase of our entity-wide information system replacement and improvement project related to our Customer Information System (CIS). In addition to replacing an end-of-life system, the implementation will result in process improvements which will, among other benefits, enhance customer satisfaction through methods such as reduced call times and first call resolution stemming from faster availability of information.

Future Capital Expenditures

Our capital expenditures in 2012 are budgeted at approximately $1.8 billion. The 2012 capital budgets for our transmission and distribution businesses are about $1,000 million and $800 million, respectively. Capital expenditures are expected to be approximately $1.8 billion in each of 2013 and 2014. These expenditures reflect the sustainment requirements of our aging infrastructure, budgeted at approximately $700 million in 2012, $950 million in 2013 and $1,000 million in 2014. Development projects, including ADS, inter-area network upgrades that reflect supply mix policies, local area supply requirements and requirements to enable DG, are budgeted at approximately $750 million in 2012, $600 million in 2013 and $550 million in 2014. These development investments also reflect customer demand work, work to facilitate DG connections and the roll out of our ADS Project. Other budgeted capital expenditures amount to approximately $350 million in 2012, $250 million in 2013 and $250 million in 2014. These expenditures include the replacement of our customer billing system to address end-of-life requirements and to further productivity realization from our enterprise-wide SAP platform.

Transmission

Transmission system capital expenditures are anticipated to be approximately $3.2 billion over the period 2012 to 2014. These include significant investments to manage the replacement and refurbishment of our aging transmission infrastructure in order to ensure a continued reliable supply of energy to customers throughout the province. The investment plan includes sustainment investments for system and stations reinvestment to replace end-of-life air blast circuit breakers, underground cable, auxiliary telecommunications equipment, aging power transformers and to comply with North American Electricity Reliability Corporation cyber security requirements. These sustaining investments are necessary to ensure that we continue to meet all regulatory, compliance, safety and environmental objectives.

Inter-area network projects, required to accommodate new generation related to supply mix policies, include our Bruce to Milton Transmission Reinforcement Project to connect nuclear generation and new wind generation in the Huron-Grey-Bruce area. This project is anticipated to be in service in 2012. Other planned major capital investments include our Midtown Electricity Infrastructure Renewal Project, that will provide additional supply capability to meet future load growth in midtown Toronto as well as areas to the west, our Southwestern Ontario Reactive Compensation Priority Project that will increase the capability of the Bruce transmission system, our Oshawa Area

Transformer Station Project to install additional 500-230 kV auto-transformer capacity within the east GTA as early as the spring of 2015 and our project to rebuild the switching station at our Hearn Transformer Station. Transmission investments for ADS and requirements to enable DG are also included in the investment plan. The Hearn Transformer Station Project, along with four other transformer station upgrades we will undertake, will collectively enable up to 600 MW of new transmission.

On December 22, 2010, we received a letter from the Minister of Energy requesting us to proceed with the necessary planning and development work for specified transmission projects and upgrades to safely and reliably accommodate additional renewable energy. The estimated capital expenditures associated with these projects and upgrades to the system are anticipated to be up to approximately $700 million over a period to the in-service dates of these projects. On February 28, 2011, the OEB amended Hydro One Networks' transmission licence in accordance with a directive to the OEB from the Minister of Energy. The licence amendment requires Hydro One Networks to develop and seek approvals for these projects in accordance with recommendations from the OPA. In a letter dated April 7, 2011, the OPA provided the scope and timing to increase short circuit and/or transformer capacity at 10 of 15 transformer stations noted in the licence to accommodate small-scale renewable generation. One of these upgrades was completed in 2011 and we are currently anticipating that six station upgrades will be in-service in 2012. For the remaining three upgrades, alternative solutions have been identified. The overall capital cost for the stations is estimated to be up to $50 million. On June 30, 2011, we received a letter from the OPA recommending the scope and timing to reconductor two circuits between Sarnia and London, the West of London Transmission Upgrade Project, to enable the connection of additional renewable generation in the west of London area with a required in-service date of December 2014. On October 3, 2011, we received a letter from the OPA recommending the scope and timing of the Southwestern Ontario Reactive Compensation Priority Project, formerly the Southwestern Ontario Series Compensation Project. After consideration of the options, the OPA has recommended that we install an SVC at our Milton Switching Station to increase the capability of the Bruce transmission system. We are awaiting an OPA recommendation regarding the construction of a new transmission line west of the City of London.

In accordance with the memorandum of agreement between Her Majesty the Queen in the Right of the Province of Ontario as represented by the Minister of Energy (the Shareholder) and our company, the Shareholder made a declaration, dated April 19, 2011, pursuant to subsection 108 (3) of the *Business Corporations Act (Ontario)* pertaining to the cost recovery of the expenditures related to the February 28, 2011 licence condition amendment. Specifically, the rights, powers and duties of our company's Directors have been restricted with regard to any decisions regarding: the pursuit of cost recovery by Hydro One Networks from microFIT and small-scale (capacity allocation exempt) FIT generation projects or proponents thereof for costs related to investments and expenditures made, or required to be made, by Hydro One Networks in order to appropriately fund the upgrades at up to 15 transformer stations pursuant to the February 28, 2011 licence condition amendment made to Hydro One Networks' transmission licence; the pursuit of cost recovery by Hydro One Networks of such costs through regulatory processes designed to ultimately recover costs from Ontario electricity consumers through electricity rates; and whether or not to pursue and implement internal cost recovery or cost mitigation measures designed to offset the costs associated with the upgrades, and to pursue further cost minimization strategies and to increase overall cost efficiencies within our company, including the timing of any such decisions. In 2011, we spent approximately $19 million on these projects, which was charged to results of operations.

In August 2010, the OEB introduced a framework for competitive designation of the development of eligible transmission projects. As a result, we did not include in our budgeted capital expenditures any projects that could meet the definition of expansion under the OEB's competitive framework. We will not undertake large capital expenditures without a reasonable expectation of recovering them in our rates, with the exception of the transformer station upgrades noted above.

The actual timing and expenditures of many development projects are uncertain as they are dependent upon various approvals including OEB leave-to-construct approvals and environmental assessment approvals; negotiations with customers, neighbouring utilities and other stakeholders; and consultations with First Nations and Métis communities, as well as the timing and level of generator contributions for enabling facilities.

Distribution

Capital expenditures within our Distribution Business are anticipated to be approximately $2.2 billion over the period 2012 to 2014. These include investments to support the sustainment of our capital infrastructure. Our core work will continue to focus on the performance of our aging distribution asset base in order to improve system reliability. There are continuing investments to replace end-of-life equipment and components, implement ADS as part of this renewal and a focus on wood pole replacements to maintain reliability. In addition, we will continue to address the demand for new load connections, trouble calls, storm restoration and system capability reinforcement.

Distribution development expenditures over the period are primarily related to customer demand work such as connections and upgrades, ADS, work to facilitate DG connections, including station upgrades, protection and control, new lines and some contestable work for which we receive capital contributions. During the 2012 and 2013 periods, we expect to manage a significant number of projects throughout the province to address load growth and the stress on our system components.

DG expenditures are based on our estimate of the number of anticipated connections, which have been reduced based on the experience gained since 2009 and changes that have occurred to the FIT Program. The budget only reflects expenditures for projects with FIT and microFIT program contracts from the OPA that are expected to connect to our distribution system.

In 2012, the ADS Project will continue to focus on the development of the technical solution and the beginning of its implementation in areas of the province where operational need is greatest. The early focus will be the integration of the Distribution Management System with intelligent power system electronic devices to support embedded DG, but it will also leverage the integration of the existing outage management system and automate crew dispatch.

Our current billing system is near the end of its life, and is costly to maintain and operate. We launched a project in 2011 to replace our existing customer system with the customer module consistent with our enterprise-wide system. The CIS Project commenced in 2011. The development will continue in 2012, and completion of system testing is expected to occur in 2013.

Summary of Contractual Obligations and Other Commercial Commitments

The following table presents a summary of our debt and other major contractual obligations as well as other major commercial commitments.

December 31, 2011 (Canadian dollars in millions)	Total	2012	2013/2014	2015/2016	After 2016
Contractual Obligations *(due by year):*					
Long-term debt – principal repayments	7,975	600	1,350	1,000	5,025
Long-term debt – interest payments	6,779	408	716	615	5,040
Inergi LP (Inergi) outsourcing agreement[1]	420	138	261	21	-
Operating lease commitments	54	9	15	10	20
Environmental and asset retirement obligations[2]	329	30	61	48	190
Total Contractual Obligations[6]	15,557	1,185	2,403	1,694	10,275
Other Commercial Commitments *(by year of expiry):*					
Bank line[3]	1,250	-	1,250	-	-
Letters of credit[4]	125	125	-	-	-
Guarantees[4]	326	326	-	-	-
Pension[5]	164	152	12	-	-
Total Other Commercial Commitments	1,865	603	1,262	-	-

[1] On May 1, 2010, we extended our Master Services Agreement with Inergi for a further three-year period. The term of the agreement, which would otherwise have expired on February 29, 2012, has been extended to February 28, 2015. Under the extended agreement, Inergi will provide business processing and information technology outsourcing services, as well as core system support related primarily to SAP implementation and optimization. The amounts disclosed include an estimated annual inflation adjustment in the range of 1.8% to 3.0%.

[2] We record a liability for the estimated future expenditures associated with the phase-out and destruction of polychlorinated biphenyl (PCB)-contaminated insulating oil from electrical equipment and for the assessment and remediation of contaminated lands, as well as asset retirement

obligations for the removal of asbestos-contaminated materials from our facilities and the decommissioning and removal of certain switching stations. The expenditure pattern reflects our planned work programs for the periods.

[3] As a backstop to our commercial paper program, we have a $1,250 million revolving standby credit facility with a syndicate of banks that matures in June 2014.

[4] We currently have outstanding bank letters of credit of $124 million relating to retirement compensation arrangements. The other $1 million included in letters of credit pertains to operating letters of credit. We have also provided prudential support to the IESO on behalf of our subsidiaries as required by the IESO's Market Rules, using parental guarantees of up to a maximum of $325 million and on behalf of two distributors using guarantees of up to a maximum of $660 thousand. Although no letters of credit are required for prudential support, we would have to resume providing bank letters of credit if our credit rating deteriorated to below the "Aa" category.

[5] Contributions to the pension fund are made one month in arrears. Contributions for 2012 are based on an actuarial valuation filed in September 2011 and effective December 31, 2009. Our annual pension contributions for 2012 will be approximately $152 million based on the expected level of pensionable earnings. Contributions beyond 2012 will be based on an actuarial valuation effective no later than December 31, 2012 and will depend on future investment returns, changes in benefits or actuarial assumptions. Pension contributions beyond 2012 are not estimable at this time.

[6] In addition, our company has entered into various agreements to purchase goods or services in support of our work programs that are enforceable and legally binding. None of these agreements is considered individually material, and the majority do not extend beyond December 31, 2012.

The amounts in the above table under long-term debt – principal repayments are not charged to our results of operations, but are reflected on our Consolidated Balance Sheet and Consolidated Statement of Cash Flows. Interest associated with this debt is recorded under financing charges on our Statement of Operations or in our capital programs. Payments in respect of operating leases and our outsourcing agreement with Inergi are recorded under OM&A expense on our Consolidated Statement of Operations or within our capital expenditures. Expenditures related to our environmental programs and asset retirement obligations are not charged to our results of operations, but are reflected on our Consolidated Balance Sheet and Consolidated Statement of Cash Flows.

RELATED PARTY TRANSACTIONS

Related party transactions primarily consist of our transmission revenues received from, and our power purchases payments made to, the IESO, which is a related party by virtue of its status as an agency of our shareholder, the Province. The year-over-year changes related to these amounts are described more fully in the discussion of our transmission revenues and purchased power costs. Other significant related party transactions include our dividends which are paid to the Province and our payments in lieu of corporate income taxes which are paid or payable to the OEFC. In January 2010, we purchased $250 million of Province of Ontario Floating Rate Notes, maturing on November 19, 2014, as a form of alternate liquidity to supplement our bank credit facilities.

CONSIDERATIONS OF CURRENT ECONOMIC CONDITIONS

Effect of Load on Revenue

The electricity load is expected to decline in 2012 due to the impact of CDM and Embedded Generation, partially offset by load growth associated with economic growth in all sectors of the Ontario economy. Overall load growth due to the economy alone is forecasted to be approximately 0.8%, with the industrial sector slightly outperforming the residential and commercial sectors. The load impact of CDM and Embedded Generation is expected to have a substantial negative impact on load growth of approximately 1.2% and 1.1%, respectively. On the whole, load is expected to decline by about 1.5%. A reduction in load, beyond the load forecast included in our approved revenue requirements, would negatively impact our financial results.

Effect of Interest Rates

Changes in interest rates will impact the calculation of the revenue requirements filed upon which our rates are based. The first component impacted by interest rates is our return on equity. The OEB-approved adjustment formula for calculating return on equity will increase or decrease by 50% of the change between the current Long Canada Bond Forecast and the risk-free rate established at 4.25% and 50% of the change in the spread in 30-year "A"-rated Canadian utility bonds over the 30-year benchmark Government of Canada bond yield established at

1.415%. We estimate that a 1% decrease in the forecasted long-term Government of Canada bond yield or the "A"-rated Canadian utility spread used in the current OEB formula for determining our ROE would reduce Hydro One Networks' transmission and distribution businesses' results of operations by approximately $18 million and $10 million, respectively. The second component of revenue requirement that would be impacted by interest rates is the return on debt. The difference between actual interest rates on new debt issuances and those approved for return by the OEB would impact our results of operations.

Input Costs and Commodity Pricing

In support of our ongoing work programs, we are required to procure materials, supplies and services. To manage our total costs, we regularly establish security of supply, strategic material and services contracts, general outline agreements, vendor alliances and we also manage a stock of commonly used items. Such arrangements are for a defined period of time and are monitored. Where advantageous, we develop long-term contractual relationships with suppliers to optimize the cost of goods and services and to ensure the availability and timely supply of critical items. As a result of our strategic sourcing practices, we do not foresee any adverse impacts on our business from current economic conditions in respect of adequacy and timing of supply and credit risk of our counter-parties. Further, we have been able to realize significant savings through our strategic sourcing initiatives.

Debt Financing

Cash generated from operations, after the payment of expected dividends, will not be sufficient to fund capital expenditures or meet debt maturity repayments and other liquidity requirements (see Risk Management and Risk Factors – Risk Associated with Arranging Debt Financing). We rely on debt financing through our MTN Program and Commercial Paper Program. Our Commercial Paper Program is supported by a total of $1,500 million in liquidity facilities as of December 31, 2011, which is comprised of a $1,250 million syndicated bank line of credit and the holding of $250 million of Province of Ontario Floating Rate Notes. In 2011, we continued issuing sufficient cost-effective debt financing through the MTN Program in the Canadian capital markets and we arranged sufficient available liquidity. Economic conditions were volatile in 2011 and we expect they will remain volatile in 2012.

Pension Plan

During 2011, the deferred pension asset reported on our Consolidated Balance Sheet increased by $6 million to $466 million. We contributed $153 million into our pension plan in 2011, including a partial wind-up payment of $4 million. We incurred $148 million in net periodic pension benefit cost. On an accounting basis, the 2010 unfunded benefit obligation of $297 million increased by $482 million to $779 million. The plan experienced positive returns of about 2.19% in the year. However, the plan was also impacted by an increase in the accrued benefit obligation, primarily as a result of a decrease in the discount rate used for accounting purposes (see Critical Accounting Estimates – Employee Future Benefits).

RISK MANAGEMENT AND RISK FACTORS

We have an enterprise risk management program that aims at balancing business risks and returns. An enterprise-wide approach enables regulatory, strategic, operational and financial risks to be managed and aligned with our strategic business objectives.

While our philosophy is that risk management is the responsibility of all employees, the Board of Directors annually reviews our company's risk tolerances and our risk profile. The Audit and Finance Committee of our Board of Directors annually reviews the status of our internal control framework. Our President and Chief Executive Officer has ultimate accountability for risk management. Our Leadership Team, comprised of direct reports to the President and Chief Executive Officer, provides senior management oversight of risk in our company. Our Chief Risk Officer is responsible for the ongoing monitoring and reviewing of our risk profile and practices, and our Executive Vice-President and Chief Financial Officer is responsible for ensuring that the risk management program is an integral part of our business strategy, planning and objective setting. Each of our subsidiaries, as well as key specialist functions and field services, are required to complete a formal risk assessment and to develop a risk mitigation strategy.

The Audit and Finance Committee, the President and Chief Executive Officer, and the Executive Vice-President and Chief Financial Officer are supported by our Chief Risk Officer. This support includes coordinating risk policies and programs, establishing risk tolerances, preparing risk assessments and profiles and assisting line and functional managers in fulfilling their responsibilities. Our internal audit staff is responsible for performing independent reviews of the effectiveness of risk management policies, processes and systems.

Ownership by the Province

The Province owns all of our outstanding shares. Accordingly, the Province has the power to determine the composition of our Board of Directors and appoint the Chair, and influence our major business and corporate decisions. We and the Province have entered into a memorandum of agreement relating to certain aspects of the governance of our company. Pursuant to such agreement, in September 2008 the Province made a declaration removing certain powers from our company's Directors pertaining to the off-shoring of jobs under the outsourcing arrangement with Inergi. In 2009, the Province required Hydro One, among other entities, to adhere to certain accountability measures regarding consulting contracts and employee travel, meal and hospitality expenses. The Province may require us to adhere to further accountability measures or may make similar declarations in the future, some of which may have a material adverse effect on our business. Hydro One's credit ratings may change with the credit ratings of the Province, to the extent the credit rating agencies link the two ratings by virtue of Hydro One's ownership by the Province.

Conflicts of interest may arise between us and the Province as a result of the obligation of the Province to act in the best interests of the residents of Ontario in a broad range of matters, including the regulation of Ontario's electricity industry and environmental matters, any future sale or other transaction by the Province with respect to its ownership interest in our company, the Province's ownership of Ontario Power Generation Inc., and the determination of the amount of dividend or proxy tax payments. We may not be able to resolve any potential conflict with the Province on terms satisfactory to us which could have a material adverse effect on our businesses.

Regulatory Risk

We are subject to regulatory risks, including the approval by the OEB of rates for our transmission and distribution businesses that permit a reasonable opportunity to recover the estimated costs of providing safe and reliable service on a timely basis and earn the approved rates of return.

The OEB approves our transmission and distribution rates based on projected electricity load and consumption levels. If actual load or consumption falls below projected levels, our ROE for either, or both, of these businesses could be materially adversely affected. Also, our current revenue requirements for these businesses are based on cost assumptions that may not materialize. There is no assurance that the OEB would allow rate increases sufficient to offset unfavourable financial impacts from unanticipated changes in electricity demand or in our costs.

Our load could also be negatively affected by successful CDM programs. The 2010 LTEP directs the OPA to achieve interim CDM targets of 4,550 MW of provincial summer peak demand and 13 TWh of cumulative energy savings by the end of 2015. The then Minister of Energy and Infrastructure's March 31, 2010 directive set a province-wide LDC CDM target of 1,330 MW and 6,000 GWh for the period 2011-2014. Hydro One Networks' targets have been set at 214 MW and 1,130 GWh, and the targets for Hydro One Brampton Networks are set at 46 MW and 190 GWh, for the period 2011-2014. These expectations are factored into our revenue requirements for OEB approval, to ensure that the targeted CDM accomplishments do not result in deteriorated revenues. There is a risk that our revenues would be reduced if these targets are exceeded. In September 2010, the *Conservation and Demand Management Code for Electricity Distributors* was established and sets out the obligations and requirements that licenced distributors must comply with in relation to the CDM targets set out in their licences. This code also sets out the conditions and rules that licenced distributors are required to follow if they choose to use OEB-approved CDM programs to meet their CDM targets. The implementation of this code could further deteriorate revenues without appropriate compensation. The OEB has recognized the need to compensate utilities for such lost revenue, but the approach, level and timing of any such compensation mechanism is yet to be determined. We are also subject to risk of revenue loss from other factors, such as economic trends and weather.

In response to the LTEP, we expect to make investments in the coming years to connect new renewable generating stations. There is the possibility that we could incur unexpected capital expenditures to maintain or improve our assets, particularly given that new technology is required to support renewable generation and unforeseen technical issues may be identified through implementation of projects. The risk exists that the OEB may not allow full recovery of such investments in the future. To the extent possible, we aim to mitigate this risk by ensuring prudent expenditures, seeking from the regulator clear policy direction on cost responsibility, and pre-approval of the need for capital expenditures.

While we expect all of our expenditures to be fully recoverable after OEB review, any future regulatory decision to disallow or limit the recovery of such costs would lead to potential asset impairment and charges to our results of operations, which could have a material adverse effect on our company.

Risk Associated with Arranging Debt Financing

We expect to borrow to repay our existing indebtedness and fund a portion of our capital expenditures. We have substantial amounts of existing debt which mature between 2012 and 2015, including $600 million maturing in 2012 and $600 million maturing in 2013. We plan to incur capital expenditures of approximately $1.8 billion in each of 2012 and 2013. Cash generated from operations, after the payment of expected dividends, will not be sufficient to fund the repayment of our existing indebtedness and capital expenditures. Our ability to arrange sufficient and cost-effective debt financing could be materially adversely affected by numerous factors, including the regulatory environment in Ontario, our results of operations and financial position, market conditions, the ratings assigned to our debt securities by credit rating agencies and general economic conditions. Any failure or inability on our part to borrow substantial amounts of debt on satisfactory terms could impair our ability to repay maturing debt, fund capital expenditures and meet other obligations and requirements and, as a result, could have a material adverse effect on our company.

Risk Associated with Transmission Projects

The amount of power that can flow through transmission networks is constrained due to the physical characteristics of transmission lines and operating limitations. Within Ontario, new and expected generation facility connections, including those renewable energy generation facilities connecting as a result of the FIT program stemming from the GEA, and load growth have increased such that parts of our transmission and distribution systems are operating at or near capacity. These constraints or bottlenecks limit the ability of our network to reliably transmit power from new and existing generation sources (including expanded interconnections with neighbouring utilities) to load centres or meet customers' increasing loads. As a result, investments have been initiated to increase transmission capacity and enable the reliable delivery of power from existing and future generation sources to Ontario consumers.

In many cases, these investments are contingent upon one or more of the following approvals and/or processes: environmental approvals; receipt of OEB approvals which can include expropriation; and appropriate consultation processes with First Nations and Métis. Obtaining OEB and/or environmental assessment approvals and carrying out these processes may also be impacted by opposition to the proposed site of transmission investments which could adversely affect transmission reliability and/or our service quality, both of which could have a material adverse effect on our company.

With the introduction on August 26, 2010 of the OEB's competitive transmission project development planning process, all interested transmitters will be required to submit a bid to the OEB for identified enabler facilities and network enhancement projects. Historically, we would have been awarded such projects through our rates and Section 92 Leave to Construct applications. The facilitation of competitive transmission could impact our future work program and our ability to expand our current transmission footprint. In addition, bid costs are only recoverable by the successful proponent. This could have a material adverse effect on our company.

Asset Condition

We continually monitor the condition of our assets and maintain, refurbish or replace them to maintain equipment performance and provide reliable service quality. Our capital and maintenance programs have been increasing to maintain the performance of our aging asset base. Execution of these plans is partially dependent on external factors, such as outage planning with the IESO and transmission-connected customers, funding approval by the OEB, and supply chain availability for equipment suppliers and consulting services. In addition, opportunities to

remove equipment from service to accommodate construction and maintenance are becoming increasingly limited due to customer and generator priorities.

Adjustments to accommodate these external dependencies have been made in our planning process, and we are focused on overcoming these challenges to execute our work programs. However, if we are unable to carry out these plans in a timely and optimal manner, equipment performance will degrade which may compromise the reliability of the provincial grid, our ability to deliver sufficient electricity and/or customer supply security and increase the costs of operating and maintaining these assets. This could have a material adverse effect on our company.

Workforce Demographic Risk

By the end of 2011, approximately 18% of our employees were eligible for retirement and by 2013 there could be up to 21% eligible to retire. Accordingly, our success will be tied to our ability to attract and retain sufficient qualified staff to replace those retiring. This will be challenging as we expect the skilled labour market for our industry to be highly competitive in the future. In addition, many of our employees possess experience and skills that will also be highly sought after by other organizations both inside and outside the electricity sector. We have already lost a considerable number of management staff, both those in executive positions and those who are logical successors for executive positions. We are therefore focused on earlier identification and more rapid development of staff who demonstrate management potential. Moreover, we must also continue to advance our technical training and apprenticeship programs and succession plans to ensure that our future operational staffing needs will be met. If we are unable to attract and retain qualified personnel, it could have a material adverse effect on our businesses.

Environmental Risk

Our health, safety and environmental management system is designed to ensure hazards and risks are identified and assessed, and controls are implemented to mitigate significant risks. This system includes a standing committee of our Board of Directors that has governance over environmental matters. Given the territory that our system encompasses and the amount of equipment that we own, we cannot guarantee, however, that all such risks will be identified and mitigated without significant cost and expense to our company. The following are some of the areas that may have a significant impact on our operations.

We are subject to extensive Canadian federal, provincial and municipal environmental regulation. Failure to comply could subject us to fines and other penalties. In addition, the presence or release of hazardous or other harmful substances could lead to claims by third parties and/or governmental orders requiring us to take specific actions such as investigating, controlling and remediating the effects of these substances. We are currently undertaking a voluntary land assessment and remediation (LAR) program covering most of our stations and service centres. This program involves the systematic identification of any contamination at or from these facilities, and, where necessary, the development of remediation plans for our company and adjacent private properties. Any contamination of our properties could limit our ability to sell these assets in the future.

We record a liability for our best estimate of the present value of the future expenditures required to comply with Environment Canada's PCB regulations and for the present value of the future expenditures to complete our LAR program. The future expenditures required to discharge our PCB obligation are expected to be incurred over the period ending 2025, while our LAR expenditures are expected to be incurred over the period ending 2020. Actual future environmental expenditures may vary materially from the estimates used in the calculation of the environmental liabilities on our balance sheet. We do not have insurance coverage for these environmental expenditures.

Under applicable regulations, we expect to incur future expenditures to identify, remove and dispose of asbestos-containing materials installed in some of our facilities. We record an asset retirement obligation for the present value of the estimated future expenditures. The estimates are based on an external, expert study of the current expenditures associated with removing such materials from our facilities.

There is also risk associated with obtaining governmental approvals, permits, or renewals of existing approvals and permits related to constructing or operating facilities. This may require environmental assessment or result in the imposition of conditions, or both, which could result in delays and cost increases.

We anticipate that all of our future environmental expenditures will continue to be recoverable in future electricity rates. However, any future regulatory decision to disallow or limit the recovery of such costs could have a material adverse effect on our company.

Scientists and public health experts have been studying the possibility that exposure to electric and magnetic fields emanating from power lines and other electric sources may cause health problems. If it were to be concluded that electric and magnetic fields present a health risk, or governments decide to implement exposure limits, we could face litigation, be required to take costly mitigation measures such as relocating some of our facilities or experience difficulties in locating and building new facilities. Any of these could have a material adverse effect on our company.

Risk of Natural and Other Unexpected Occurrences

Our facilities are exposed to the effects of severe weather conditions, natural disasters, man-made events including cyber and physical terrorist type attacks and, potentially, catastrophic events, such as a major accident or incident at a facility of a third party (such as a generating plant) to which our transmission or distribution assets are connected. Although constructed, operated and maintained to industry standards, our facilities may not withstand occurrences of this type in all circumstances. We do not have insurance for damage to our transmission and distribution wires, poles and towers located outside our transmission and distribution stations resulting from these events. Losses from lost revenues and repair costs could be substantial, especially for many of our facilities that are located in remote areas. We could also be subject to claims for damages caused by our failure to transmit or distribute electricity. Our risk is partly mitigated because our transmission system is designed and operated to withstand the loss of any major element and possesses inherent redundancy that provides alternate means to deliver large amounts of power. In the event of a large uninsured loss we would apply to the OEB for recovery of such loss; however, there can be no assurance that the OEB would approve any such applications, in whole or in part, which could have a material adverse effect on our net income.

Risk Associated with IT Infrastructure

Our ability to operate effectively in the Ontario electricity market is in part dependent upon us developing, maintaining and managing complex IT systems which are employed to operate our transmission and distribution facilities, financial and billing systems, and business systems. Our increasing reliance on information systems and expanding data networks increases our exposure to information security threats. We mitigate this risk through various methods including the use of security event management tools on our power and business systems, by separating our power system network from our business system network, by performing scans of our systems for known cyber threats and by providing company-wide awareness training to our personnel. We also engaged the services of external experts to evaluate the security and privacy protection aspects of our smart meter program related to customer data. We perform vulnerability assessments on our critical cyber assets and we ensure security and privacy controls are incorporated into new IT capabilities. Although these security and system disaster recovery controls are in place, there can be no guarantee that there will not be system failures or security breaches. Any such system failures or security breaches could have a material adverse effect on our company.

Pension Plan Risk

We have a defined benefit registered pension plan for the majority of our employees. Contributions to the pension plan are established by actuarial valuations which are filed with the Financial Services Commission of Ontario on a triennial basis. The most recently filed valuation was prepared as at December 31, 2009 and was filed in September, 2010. Our company contributed $145 million in respect of 2010 and $148 million in respect of 2011 to its pension plan to satisfy minimum funding requirements. A one-time additional payment of $48 million was made in December 2010 and an additional contribution of $3.8 million was also made in 2011 to complete the funding associated with a partial plan wind-up. Contributions beyond 2011 will depend on investment returns, changes in benefits and actuarial assumptions, and may include additional voluntary contributions from time to time. Nevertheless, future contributions are expected to be significant. A determination by the OEB that some of our pension expenditures are not recoverable from customers could have a material adverse effect on our company, and this risk may be exacerbated as the quantum of required pension contributions increases.

Market and Credit Risk

Market risk refers primarily to the risk of loss that results from changes in commodity prices, foreign exchange rates and interest rates. We do not have commodity risk. We do have foreign exchange risk as we enter into agreements to purchase materials and equipment associated with our capital programs and projects that are settled in foreign currencies. This foreign exchange risk is not material. We could in the future decide to issue foreign currency-denominated debt which we would anticipate hedging back to Canadian dollars, consistent with our company's risk management policy. We are exposed to fluctuations in interest rates as our regulated rate of return is derived using a formulaic approach, which is in part based on the forecast for long-term Government of Canada bond yields. We estimate that a 1% decrease in the forecasted long-term Government of Canada bond yield used in determining our ROE would reduce our Transmission Business' net income by approximately $18 million and our Hydro One Networks' Distribution Business' net income by approximately $10 million. Our net income is adversely impacted by rising interest rates as our maturing long-term debt is refinanced at market rates. We periodically utilize interest-rate swap agreements to mitigate elements of interest-rate risk.

Financial assets create a risk that a counter-party will fail to discharge an obligation, causing a financial loss. Derivative financial instruments result in exposure to credit risk, since there is a risk of counter-party default. We monitor and minimize credit risk through various techniques, including dealing with highly-rated counter-parties, limiting total exposure levels with individual counter-parties, and by entering into master agreements which enable net settlement and by monitoring the financial condition of counter-parties. We do not trade in any energy derivatives. We do, however, have interest-rate swap contracts outstanding from time to time. Currently, there are no significant concentrations of credit risk with respect to any class of financial assets. We are required to procure electricity on behalf of competitive retailers and embedded LDCs for resale to their customers. The resulting concentrations of credit risk are mitigated through the use of various security arrangements, including letters of credit, which are incorporated into our service agreements with these retailers in accordance with the OEB's Retail Settlements Code. The failure to properly manage these risks could have a material adverse effect on our company.

Labour Relations Risk

The substantial majority of our employees are represented by either the PWU or the Society of Energy Professionals. Over the past several years, significant effort has been expended to increase our flexibility to conduct operations in a more cost-efficient manner. Although we have achieved improved flexibility in our collective agreements, including a reduction in pension benefits for Society staff hired after November 2005 similar to a previous reduction affecting management staff, we may not be able to achieve further improvement. The existing collective agreement with the PWU will expire on March 31, 2013 and the existing Society collective agreement will expire on March 31, 2013. We face financial risks related to our ability to negotiate collective agreements consistent with our rate orders. In addition, in the event of a labour dispute, we could face operational risk related to continued compliance with our licence requirements of providing service to customers. Any of these could have a material adverse effect on our company.

Risk from Transfer of Assets Located on Indian Lands

The transfer orders by which we acquired certain of Ontario Hydro's businesses as of April 1, 1999 did not transfer title to some assets located on lands held for bands of Indians under the *Indian Act* (Canada). Currently, the OEFC holds legal title to these assets and we manage them until we have obtained necessary authorizations to complete the title transfer. To occupy reserve land, we must have valid permits issued by Her Majesty the Queen in the Right of Canada. For each permit, we must negotiate an agreement (in the form of a Memorandum of Understanding) with the band, OEFC and any First Nations individuals who have occupancy rights. The agreement includes provisions whereby the First Nations consent to the federal Department of Aboriginal Affairs and Northern Development issuing a permit. It is difficult to predict the aggregate amount that we may have to pay, either on an annual or one-time basis, to obtain the required agreements from the Indian bands. However, we anticipate that the amount will exceed the $1,142,743 that we paid in 2011. OEFC will continue to hold these assets until we are able to negotiate agreements with the Indian bands and occupants. If we cannot reach satisfactory agreements and obtain federal permits, we may have to relocate these assets from the Indian reserve lands to other locations at a cost that could be substantial. In a limited number of cases, it may be necessary to abandon a line and replace it with diesel generation facilities. The costs relating to these assets could have a material adverse effect on our net income if we are not able to recover them in future rate orders.

Risk Associated with Outsourcing Arrangement

Consistent with our strategy of reducing operating costs, we amended and extended our outsourcing services agreement with Inergi, effectively renewing the arrangement until February 28, 2015. If the agreement with Inergi is terminated for any reason, we could be required to incur significant expenses to transfer to another service provider, which could have a material adverse effect on our business, operating results, financial condition or prospects.

Risk from Provincial Ownership of Transmission Corridors

Pursuant to the *Reliable Energy and Consumer Protection Act, 2002*, the Province acquired ownership of the transmission corridor lands underlying our transmission system. Although we have the statutory right to use the transmission corridors, we may be limited in our ability to expand our systems. Also, other uses of the transmission corridors by third parties in conjunction with the operation of our systems may increase safety or environmental risks, which could have an adverse effect on our company.

CRITICAL ACCOUNTING ESTIMATES

The preparation of our Consolidated Financial Statements requires us to make estimates and judgements that affect the reported amounts of assets, liabilities, revenues and costs, and related disclosures of contingencies. We base our estimates and judgements on historical experience, current conditions and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgements about the carrying values of assets and liabilities as well as identifying and assessing our accounting treatment with respect to commitments and contingencies. Actual results may differ from these estimates and judgements under different assumptions or conditions.

We believe the following critical accounting estimates involve the more significant estimates and judgements used in the preparation of our Consolidated Financial Statements:

Regulatory Assets and Liabilities

Regulatory assets as at December 31, 2011 amounted to $1,088 million and principally relate to future income tax, environmental costs, and the pension variance account. We have also recorded regulatory liabilities amounting to $660 million as at December 31, 2011. These amounts pertain primarily to deferred pension, Rider 8, the external revenue variance account, retail settlement variance accounts and future income tax. These assets and liabilities can be recognized for rate-setting and financial reporting purposes only if the OEB directs the relevant regulatory treatment or if future OEB direction is judged to be probable. If management judges that it is no longer probable that the OEB will include a regulatory asset or liability in the setting of future rates, the relevant regulatory asset or liability would be charged or credited to results of operations in the period in which that judgement is made.

Environmental Liabilities

We record liabilities and related regulatory assets based on the present value of the estimated future expenditures to be made to satisfy obligations related to legacy environmental contamination inherited upon our de-merger from Ontario Hydro in 1999. These liabilities fall into two main categories: the management of assets contaminated with PCB-laden mineral oils and the assessment and remediation of contaminated lands. In determining the amounts to be recorded as environmental liabilities, we estimate the current cost of completing mitigation work now and make assumptions for when the future expenditures will actually be incurred in order to generate future cash flow information. A long-term inflation assumption of 2% is used to express our current cost estimates as estimated future expenditures. Future estimated LAR expenditures are expected to be incurred over the period ending 2020 and are discounted using factors ranging from 3.57% to 4.87%, depending on the appropriate rate for the period when the particular obligation was recorded. Consistent with the requirements of Environment Canada's PCB regulations issued on September 17, 2008, estimated future PCB remediation expenditures are expected to be incurred over the period ending 2025 and are discounted using factors ranging from 5.14% to 6.25%, depending on the appropriate rate in effect in the period when each obligation was recorded.

Recording a liability now for such long-term future expenditures requires that many other assumptions be made, such as the number of contaminated properties and the extent of contamination; the number of assets to be inspected, tested and mitigated; oil volumes; contamination levels of equipment with PCBs; and the timing of work. All factors used in deriving our environmental liabilities represent our best estimates based on our planned approach of meeting current legislative and regulatory requirements. These requirements include Environment Canada's regulations governing the management, storage and disposal of PCBs. However, it is reasonably possible that numbers or volumes of contaminated assets, current cost estimates, inflation estimates and the actual pattern of annual future cash flows may differ significantly from our current assumptions. Estimated environmental liabilities are reviewed annually or more frequently if significant changes in regulation or other relevant facts occur. Estimate changes are accounted for prospectively.

Employee Future Benefits

We provide future benefits to our current and retired employees, including pension, group life insurance, health care and long-term disability.

In accordance with our rate orders, we record pension costs when employer contributions are paid to the pension fund (the Fund) in accordance with the *Pension Benefits Act* (Ontario). Our annual pension contributions in respect of 2011 were approximately $152 million, $148 million of which was based on an actuarial valuation effective December 31, 2009. Contributions after 2012 will be based on an actuarial valuation effective December 31, 2012, and will depend on investment returns, changes in benefits or actuarial assumptions. Pension costs are also disclosed in the notes to the Consolidated Financial Statements on an accrual basis. We record employee future benefit costs other than pension on an accrual basis. The accrual costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. The assumptions were determined by management recognizing the recommendations of our actuaries.

The assumed return on pension plan assets of 6.50% per annum is based on expectations of long-term rates of return at the beginning of the fiscal year and reflects a pension asset mix consistent with the Fund's investment policy. During the year the Fund's target asset mix was 62% exposure to equities, 33% to fixed income and 5% in alternative assets consisting of hedge funds and private equity. On August 11, 2011, the Board approved a new target policy asset mix of 60% exposure to equities, 35% exposure to fixed income and 5% in alternative assets consisting of real estate and infrastructure. The implementation of this new policy asset mix will begin in 2012. Returns on the respective portfolios are determined with reference to published Canadian and U.S. stock indices and long-term bond and treasury bill indices. The assumed rate of return on pension plan assets reflects our long-term expectations. We believe that this assumption is reasonable because, with the Fund's balanced investment approach, the higher volatility of equity investment returns is intended to be offset by the greater stability of fixed income and short-term investment returns. The net result, on a long-term basis, is a somewhat lower return than might be expected by investing in equities alone. In the short term, the plan can experience aberrations in actual return. In 2011, the return on pension plan assets was lower than this long-term assumption but was higher than in 2010.

The discount rate used to calculate the accrued benefit obligations is determined each year end by referring to the most recently available market interest rates based on AA corporate bond yields reflecting the duration of the applicable employee future benefit plan. The discount rates at December 31, 2011 declined to 5.25% from 5.75% used at December 31, 2010 in conjunction with decreases in bond yields over this period. The decrease in discount rates has resulted in a corresponding increase in liabilities.

Yields on AA corporate bonds declined by approximately 40-50 basis points between December 31, 2010 and December 31, 2011. Based on the duration of the plan's liabilities, discount rates would be 5.25% per annum for each of the pension plan, the post-retirement benefit plan and the post-employment plan. The overall discount rate applied to all plans for liability valuation purposes as at December 31, 2011 was 5.25%.

Further, based on differences between long-term Government of Canada nominal bonds and real return bonds, the implied inflation rate has decreased from the range of 2.25% to 2.50% per annum as at December 31, 2010 to approximately 2.00% per annum as at December 31, 2011. Given the Bank of Canada's commitment to keep long-term inflation between 1.00% and 3.00%, management believes that the current implied rate is reasonable to use as a long-term assumption and as such, has used a 2.00% per annum inflation rate for liability valuation purposes as at December 31, 2011.

The costs of employee future benefits other than pension are determined at the beginning of the year. The costs are based on assumptions for expected claims experience and future health care cost inflation. A 1% increase in the health care cost trends would result in an increase in service cost and interest cost of about $20 million per year and an increase in the year-end obligation of about $174 million.

Employee future benefits are included in labour costs that are either charged to results of operations or capitalized as part of the cost of fixed and intangible assets. Changes in assumptions will affect the accrued benefit obligation of the employee future benefits and the future years' amounts that will be charged to our results of operations or capitalized as part of the cost of fixed and intangible assets.

Goodwill and Asset Impairment

In assessing the recoverability of goodwill, we must make assumptions regarding estimated future cash flows and other factors to determine the fair value of the distribution reporting unit. If these estimates or their related assumptions change in the future, we may be required to record impairment charges related to goodwill. An impairment review of goodwill was carried out during 2011 and we determined that the carrying value of our goodwill has not been impaired.

Within our regulated businesses, carrying costs of our other assets are recovered in our revenue requirements and are included in rate base, where they earn a return. Such assets would be tested for impairment only in the event that the OEB disallowed recovery or if such a disallowance was judged to be probable. We periodically monitor the assets of our unregulated Telecom Business for indications of impairment. No asset impairments have been recorded to date for any of our businesses.

STATUS OF OUR TRANSITION TO UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

Accounting Framework for External Reporting

We previously planned to adopt IFRS effective January 1, 2012 with comparative restatement of our 2011 results. In the absence of a definitive International Accounting Standards Board (IASB) plan to provide guidance on rate-regulated accounting, we began evaluating the option of adopting US GAAP in lieu of IFRS in the first quarter of 2011. On July 7, 2011, we filed our application with the OSC for exemptive relief from the requirements of section 3.2 of National Instrument 52-107, *Acceptable Accounting Policies and Auditing Standards*, that would otherwise require us to file our Consolidated Financial Statements based on IFRS starting with reporting periods commencing after January 1, 2012. Our application requested approval to instead adopt US GAAP, without becoming a Securities and Exchange Commission registrant, for our 2012, 2013 and 2014 fiscal years. This was approved by the OSC on July 21, 2011, and the requested exemptive relief was granted. In addition, a change to Ontario Regulation 395/11 was made during 2011 that requires us to prepare our Consolidated Financial Statements in accordance with US GAAP for financial years on or after January 1, 2012. Our Board of Directors has approved a resolution authorizing us to report under US GAAP.

Under US GAAP, our financial reporting will be more stable and comparable with our current Canadian GAAP results than it would have been under IFRS. The use of US GAAP will also facilitate benchmarking to other large North American utilities in terms of our results, as well as facilitate transmission cost comparisons for the OEB. Our March 31, 2012 Consolidated Financial Statements will be prepared based on US GAAP with one year of comparative restatement. Our opening US GAAP Consolidated Balance Sheet as at January 1, 2010 will be based on a retrospective application of US GAAP. As a result of this decision, our IFRS conversion project efforts have been reduced. However, our work will be managed in such a way that it can effectively be restarted if a future transition to IFRS is required.

In anticipation of OSC approval of our application, we initiated a US GAAP conversion project that consists of three phases: scoping and diagnostic; analysis; and implementation. The scoping and diagnostic phase of our project involved a high-level review of the major differences between existing Canadian and US GAAP. We completed this phase in the second quarter. We also substantially completed the second or analytical phase of our project in the second quarter. This phase involved assessment of the impacts of adopting US GAAP on our Consolidated Financial Statements, including measurement, classification, presentation and disclosure. The major differences identified to

date include a change to the presentation of preferred shares on the balance sheet and adjustments related to accounting for employee future benefits costs. Our preferred shares, which are held entirely by the Province, will be classified as mezzanine equity under US GAAP. In addition, the net pension obligation at the end of the reporting period will be recognized on our Consolidated Balance Sheet with an offsetting regulatory asset. In accordance with OEB rate orders, pension costs are recorded under Canadian GAAP when employer contributions are paid to the pension fund in accordance with the *Pension Benefits Act* (Ontario). Pension costs will be recorded in the same way under US GAAP. Employee future benefits other than pension are, and will continue to be recorded on an accrual basis. There are minor differences between Canadian and US GAAP for certain employee future benefits costs. However, we do not expect any significant change to the net asset position on our Consolidated Balance Sheet. Nor do we expect significant impacts on our Consolidated Statement of Operations following the application of US GAAP to our employee future benefits costs.

We continue to assess and refine the impact that the conversion will have upon our disclosures.

Accounting Framework for Rate Setting

Consistent with our approval from the OSC to adopt US GAAP for external financial reporting and securities filings, on July 15, 2011, we filed a Motion to Vary the OEB's 2012 Transmission rate decision seeking approval to adopt US GAAP as the basis for regulatory accounting and rate setting in place of the OEB's approved modified IFRS basis. We also included a request to adopt US GAAP for our Hydro One Networks Distribution Business in this application. While the OEB denied our requests for procedural reasons, it initiated a specific proceeding to evaluate the use of US GAAP by our Transmission Business and to determine any required revisions to the approved 2012 revenue requirement. On November 23, 2011, the OEB issued its decision with reasons approving the use of US GAAP by our Transmission Business. In this decision, the OEB determined that we should make a separate application to request the use of US GAAP for our Distribution Business. On December 1, 2011 we submitted our application requesting that our Distribution Business be authorized to use US GAAP for rate setting effective January 1, 2012. A decision on our request to adopt US GAAP for our Distribution Business is anticipated in the first quarter of 2012. On December 16, 2011, we made a similar request to the OEB in respect of our Remote Communities business. We did not make a request to adopt US GAAP on behalf of our Hydro One Brampton Networks subsidiary and, as a result, it will have its rates set based on modified IFRS once its current IRM period is complete.

Debt Covenants

We have the customary covenants normally associated with long-term debt. Among other things, our long-term debt covenants limit our permissible debt as a percentage of our total capitalization. As part of our US GAAP transition, we analyzed the impact of potential accounting changes on our debt covenants. Based on the work performed in phases one and two of our project, after conversion to US GAAP we expect to remain in compliance with these covenants. We also amended our bond indentures to allow us to use US GAAP for external reporting purposes.

Internal Control over Financial Reporting and Disclosure Controls and Procedures

We have assessed the impact of conversion from Canadian GAAP to US GAAP on our internal controls over financial reporting and on our disclosure controls and procedures. We do not anticipate any changes to existing controls or a need for additional controls as a result of conversion.

Financial Reporting Expertise

Given the similarities between US GAAP and current Canadian GAAP, our US GAAP training efforts are focused on specific areas of difference between the two accounting frameworks and these efforts are initially being targeted to specific staff, senior executive management and the Audit and Finance Committee of our Board of Directors. In the first quarter of 2012, additional formal training will be provided to other finance and operational staff who are not directly involved in our conversion project. This training will concentrate on communicating the key differences between Canadian and US GAAP at a level of detail that is appropriate to meet their respective needs.

IT Systems

We have completed a preliminary assessment of the impacts of converting to US GAAP on our IT systems. Our recently implemented SAP enterprise systems allow for flexibility in the application of accounting policies and,

given the similarities between Canadian and US GAAP, we anticipate that any required IT system changes to accommodate US GAAP will be comparatively minor. Our systems have been designed to be sufficiently flexible to allow the future adoption of IFRS should this be required.

DISCLOSURE CONTROLS AND INTERNAL CONTROLS OVER FINANCIAL REPORTING (ICFR)

Our Supply Chain Enhancement Project to develop an operating framework that outlines the strategy and objectives of our supply chain was implemented in the second quarter of 2011. The resulting new processes have been reviewed to assess the impact on the control environment. Process documents have been updated and controls have been tested for design and operating effectiveness.

In an effort to optimize our customer service operations, we have initiated our CIS Project. The new system will replace two legacy applications currently in use to provide billing, customer contact, field services, settlements and customer choice administration to our distribution customers and key constituents. The CIS Project is currently in the final stages of the design phase which will be followed by the build phase. During the build phase, CIS process documentation will continue to be reviewed and analyzed to ensure that key risks remain adequately addressed by our internal controls. Any new controls will be documented and tested as part of our ongoing certification process.

In compliance with the requirements of National Instrument 52-109, *Certification of Disclosure in Issuers' Annual and Interim Filings*, our Certifying Officers have reviewed and certified the Consolidated Financial Statements for the year ended December 31, 2011, together with other financial information included in our annual securities filings. Our Certifying Officers have also certified that disclosure controls and procedures (DC&P) have been designed to provide reasonable assurance that material information relating to our company is made known within our company. Based on the evaluation of the design and operation of our DC&P, our Certifying Officers concluded that our DC&P was effective as at December 31, 2011. Further, our Certifying Officers have also certified that ICFRs have been designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of Consolidated Financial Statements. Based on the evaluation of the design and operating effectiveness of our company's ICFR, our Certifying Officers concluded that our ICFR was effective as at December 31, 2011.

SELECTED ANNUAL INFORMATION

The following table sets forth audited annual information for each of the three years ended December 31, 2009, 2010 and 2011. This information has been derived from our audited annual Consolidated Financial Statements.

Consolidated Statements of Operations *Year ended December 31 (Canadian dollars in millions, except earnings per common share)*	**2011**	**2010**	**2009**
Revenues	5,471	5,124	4,744
Net income	641	591	470
Basic and fully diluted earnings per common share	6.228	5.727	4.528

Consolidated Balance Sheets *Year ended December 31 (Canadian dollars in millions, except cash dividends per share)*	**2011**	**2010**	**2009**
Total assets	18,368	17,322	15,635
Total long-term debt	7,999	7,778	6,881
Cash dividends per common share	1.500	100	1.700
Cash dividends per preferred share	1.375	1.375	1.375

OUTLOOK

To achieve our vision to be the leading electricity delivery company in North America, we will continue to concentrate on our strategic objectives of safety, customer satisfaction, continuous innovation, reliability, protection of the environment, employee engagement, shareholder value and productivity and cost-effectiveness. We work in

an environment where safety is of the utmost importance. Our people underpin everything we do, and as such, we remain resolute in our commitment to safety. We will continue to focus our efforts to improve our customers' satisfaction by meeting the unique needs of our diverse customer base through dialogue to understand their needs. We will install innovative solutions that improve the reliability and efficiency of the transmission and distribution systems and provide our customers more capability to manage their own costs. The ADS is a key element in our investment in innovation. We will provide a robust and reliable provincial grid that accommodates the province's emerging generation profile, manages an aging asset base and meets demand requirements through prudent expansion and effective maintenance. We will support the connection of renewable energy sources through the incorporation of ADS technology into our distribution system. We will continue to focus on reducing our carbon footprint through the delivery of clean and renewable energy and through measures that allow our customers to manage and reduce their energy use. We will also continue to strive for productivity through efficiency and effective management of costs, which is key to achieving value for our customers and our shareholder.

Following the release of the LTEP late in 2010, the Province issued a supply mix directive on February 17, 2011 that will form the basis for a new IPSP. The LTEP, and the proposed IPSP, support the continued procurement of new, cleaner generation consistent with the energy strategies set out in the GEA. Our transmission license was amended during the year to require us to undertake three of five priority projects listed in the LTEP as well as up to 15 transmission station upgrades to accommodate small-scale renewable generation.

We are planning significant investments in transmission and distribution infrastructure and the continued proactive maintenance of our assets to ensure the electricity system's reliability in the public interest. The reliability of our current and future system is dependent on addressing aging infrastructure, making required asset replacements and ensuring continuous maintenance programs. Our investment plan supports the achievement of the Province's phase-out of coal-fired generation, renewable and nuclear objectives, facilitates the development and use of renewable energy resources, promotes system efficiency, sustains equipment performance, meets customers' service quality needs and facilitates the integration of new supply. We remain focused on balancing our expenditures associated with the LTEP, the costs and challenges of connecting DG, the execution of our sustainment programs and the impacts of rates on our customers.

In late 2010, the OEB approved our 2011 and 2012 transmission rates, with a revenue requirement for 2012 of $1,658 million, reflecting the adoption of modified IFRS. On November 23, 2011, the OEB granted our request to adopt US GAAP for our Transmission Business effective January 1, 2012 and on December 20, 2011 approved a revised 2012 revenue requirement of $1,418 million. The approved revenue requirement will support aging critical infrastructure, area supply projects and the Province's policy objectives.

A request was submitted on December 1, 2011 to the OEB to grant Hydro One Networks' Distribution Business approval of the use of US GAAP for rate-setting, regulatory accounting and reporting purposes effective January 1, 2012. Once approved by the OEB, the initiative to move our financial reporting to a US GAAP basis will have a beneficial impact by avoiding an increase in customer rates related to capitalization policies allowed under modified IFRS.

A transmission cost-of-service rate application is planned for 2013 and 2014 with a proposed regulated return on equity based on the application of the OEB's cost-of-capital report. We are currently reviewing our options for our Distribution Business.

The actual timing and expenditures in our business plan are predicated on obtaining various approvals including OEB approvals and environmental assessment approvals; successful negotiations with customers, neighbouring utilities and other stakeholders; and consultations with First Nations and Métis communities. Further, we have made assumptions in our plan regarding cost responsibility and funding, consistent with the GEA regulations and amended TSC and DSC.

As stewards of significant electricity assets, we are committed to the protection and sustainment of the environment for future generations. We are working towards being an environmental leader in our industry, by distributing clean and renewable energy, by upgrading our electricity grid, by minimizing the impacts of our own operations, and ensuring that environmental factors are considered in making our business decisions. Our commitment to the environment has been recognized by *Corporate Knights* magazine. We have also partnered with various communities and First Nations and Métis groups along the Bruce to Milton corridor for a biodiversity initiative that will enhance the natural environment in the local communities and seek to improve local biodiversity.

Key enablers of the successful implementation of our work program are our human and material resourcing strategies. Our human resource strategy is focused on hiring through our apprenticeship program and our association with universities, colleges and our unions, as well as skills development and retention. Effective use of human resources and ensuring correct skills will be critical to attaining the balance between meeting the asset needs and mitigating rate impact on the customer. Although the work program is assumed to grow moderately over the 2012 and 2013 years, no increase in regular staff numbers is anticipated over that period. With regard to materials, we are seeing a need for increasing lead times and costs as market shortages emerge globally. Consequently, materials sourcing strategies continue to be developed and implemented to ensure the availability of materials to support our work programs.

We remain committed to a prudent and measured approach to distribution rationalization. We have considered and will continue to consider and respond to opportunities for acquisitions or divestitures, on a voluntary and commercial basis. Our plan does not include funding for LDC acquisitions or assume any disposition of our service territory. These opportunities will be managed as they arise. Our plan also does not incorporate any projects related to competitive transmission. However, as leaders in the sector, we plan to bid on key projects.

We will continue to increase enterprise value through productivity improvements and cost-effectiveness driven by technology. Over the last three years, we have replaced most of our core IT systems with an enterprise-wide IT system. We will leverage this investment as a platform for further effectiveness and efficiency gains, including enhancements in strategic sourcing. In addition, significant opportunity resides with smart meters and the proliferation of an ADS, including energy efficiency, demand response and distributed-resources technologies.

As part of our critical role as an enabler, we will continue to take a leadership role in the development and maintenance of the transmission and distribution grids.

FORWARD-LOOKING STATEMENTS AND INFORMATION

Our oral and written public communications, including this document, often contain forward-looking statements that are based on current expectations, estimates, forecasts and projections about our business and the industry in which we operate and include beliefs and assumptions made by the management of our company. Such statements include, but are not limited to statements about our strategy and our performance measures and targets; statements related to the IPSP, including the consultation process; statements about smart meters and the ADS including their capabilities, installation and areas of implementation; expectations regarding developments in the statutory and operating framework for electricity distribution and transmission in Ontario including the impacts of changes to codes, licences, rules, new regulatory guidelines, tariff rate changes, cost recovery, return on equity, rate structures, revenue requirements and impacts on an average customer's total bill; expectations regarding the timing and content of applications to, hearings with and decisions from the OEB and other regulatory bodies; statements related to the LTEP; statements about the FIT review; expectations regarding the OEB's renewed regulatory framework for electricity distributors and transmitters including the anticipated outcome; statements about outstanding legal proceedings; statements regarding the transition to TOU billing; expectations regarding future renewable energy generation; statements regarding our liquidity and capital resources and their use; expectations regarding our financing activities, including our capital management objectives and our ability to access the capital markets; expectations about our maturing debt and interest payments; statements regarding our ongoing and planned projects and/or initiatives including the expected approval process, and the expected results of these projects and/or initiatives and their completion dates; expectations regarding our participation in future projects; expectations regarding the recoverability of liabilities and assets; statements regarding expected future capital expenditures, the timing of these expenditures and our investment plans; statements regarding contractual obligations and other commitments; statements regarding the effect of load on our revenue including the anticipated impact of CDM programs; expectations regarding our pursuance of OEB-approved CDM programs; the effect of interest rates on our revenue requirements and results of operations; statements regarding the estimated impact of changes in the forecasted long-term Government of Canada bond yield on our results of operations; impacts to our business in respect of the adequacy and timing of supply of materials, supplies and services and credit risk of our counter-parties; expectations regarding future pension contributions, effect of health care cost trend on the future benefits costs and the performance of our pension plan; the possibility of the Province making declarations pursuant to our memorandum of agreement with them; statements regarding possible future actions of the Province and regulatory

bodies; expectations regarding connections of new generation to our transmission and distribution systems; expectations regarding asset condition; statements regarding workforce demographics and the market for skilled labour; statements regarding the amount and timing of future estimated environmental expenditures, including with respect to LAR and PCBs; statements about future asbestos removal expenditures and asset retirement obligations; expectations regarding our information technology strategy and enterprise reporting system; the possibility that we could in future decide to issue foreign currency-denominated debt; expectations regarding anticipated expenditures associated with transferring assets located on Indian lands; statements about our outsourcing arrangement with Inergi; statements regarding provincial ownership of our transmission corridors; statements about critical accounting estimates; statements about US GAAP and our adoption of US GAAP; statements about the outlook period including our expectations regarding our role within the industry, our financial returns, our credit rating and credit quality and structural changes to our company. Words such as "expect," "anticipate," "intend," "attempt," "may," "plan," "will", "believe," "seek," "estimate," "goal," "aim," "target," and variations of such words and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking statements. We do not intend, and we disclaim any obligation to update any forward-looking statements, except as required by law.

These forward-looking statements are based on a variety of factors and assumptions including, but not limited to the following: no unforeseen changes in the legislative and operating framework for Ontario's electricity market; no unfavourable decisions from the OEB and other regulatory bodies concerning outstanding rate and other applications; no delays in obtaining the required approvals; no unforeseen changes in rate orders or rate structures for our Distribution and Transmission businesses; a stable regulatory environment; no unfavourable changes in environmental regulation; and no significant event occurring outside the ordinary course of business. These assumptions are based on information currently available to us, including information obtained from third-party sources. Actual results may differ materially from those predicted by such forward-looking statements. While we do not know what impact any of these differences may have, our business, results of operations, financial condition and our credit stability may be materially adversely affected. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking statements include, among other things.

- the impact of the GEA and the LTEP, including unexpected expenditures arising therefrom;
- results arising from the FIT review and the IPSP consultation process;
- the risk that previously granted regulatory approvals may be subsequently challenged, appealed or overturned;
- public opposition to and delays or denials of the requisite approvals and accommodations for our planned projects;
- the risks associated with being controlled by the Province including the possibility that the Province may make declarations pursuant to the memorandum of agreement, as well as potential conflicts of interest that may arise between us, the Province and related parties;
- the risks associated with being subject to extensive regulation including risks associated with OEB action or inaction;
- the timing and results of regulatory decisions regarding our revenue requirements, rates, and the recoverability of costs, liabilities and assets, as well as changes to rules under various regulatory body review;
- the potential impact of CDM programs on our load and our revenues;
- unanticipated changes in electricity demand or in our costs;

- the risk that we are not able to arrange sufficient cost-effective financing to repay maturing debt and to fund capital expenditures and other obligations;
- the risks associated with the execution of our capital and operation, maintenance and administration programs necessary to maintain the performance of our aging asset base;
- the risk that we may not recover all of our project costs to prepare a bid associated with the OEB's Framework for Transmission Project Development Plans;
- the risk that we will be unable to source the materials necessary to support our work programs;
- the risks related to our workforce demographic and our potential inability to attract and retain qualified personnel;
- the risk that assumptions that form the basis of our recorded environmental liabilities and related regulatory assets may change;
- the risk of currently undetermined future asbestos removal costs;
- the risk to our facilities posed by severe weather conditions, natural disasters or catastrophic events and our limited insurance coverage for losses resulting from these events;
- the risks associated with information system security and with maintaining a complex information technology systems infrastructure and transitioning most of our financial and business processes to an integrated business and financial reporting system;
- future interest rates, future investment returns, inflation, changes in benefits and changes in actuarial assumptions;
- the risks associated with changes in interest rates;
- the risk that we may incur significant costs associated with transferring assets located on Indian lands;
- the potential that we may incur significant expenses to replace some or all of the functions currently outsourced if our agreement with Inergi is terminated; and
- the impact of the ownership by the Province of lands underlying our transmission system.

We caution the reader that the above list of factors is not exhaustive. Some of these and other factors are discussed in more detail in the section Risk Management and Risk Factors in this Management's Discussion and Analysis (MD&A). You should review this section in detail.

In addition, we caution the reader that information provided in this MD&A regarding our outlook on certain matters, including future expenditures, is provided in order to give context to the nature of some of our future plans and may not be appropriate for other purposes.

This MD&A is dated as at February 10, 2012. Additional information about our company, including our Annual Information Form, is available on SEDAR at www.sedar.com.

HYDRO ONE INC.
MANAGEMENT'S REPORT

The Consolidated Financial Statements, Management's Discussion and Analysis (MD&A) and related financial information presented in this Annual Report have been prepared by the management of Hydro One Inc. (Hydro One or the Company). Management is responsible for the integrity, consistency and reliability of all such information presented. The Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in Canada and applicable securities legislation. The MD&A has been prepared in accordance with National Instrument 51-102, Part 5.

The preparation of the Consolidated Financial Statements and information in the MD&A involves the use of estimates and assumptions based on management's judgement, particularly when transactions affecting the current accounting period cannot be finalized with certainty until future periods. Estimates and assumptions are based on historical experience, current conditions and various other assumptions believed to be reasonable in the circumstances, with critical analysis of the significant accounting policies followed by the Company as described in Note 2 to the Consolidated Financial Statements. The preparation of the Consolidated Financial Statements and the MD&A includes information regarding the estimated impact of future events and transactions. The MD&A also includes information regarding sources of liquidity and capital resources, operating trends, risks and uncertainties. Actual results in the future may differ materially from the present assessment of this information because future events and circumstances may not occur as expected. The Consolidated Financial Statements and MD&A have been properly prepared within reasonable limits of materiality and in light of information up to February 10, 2012.

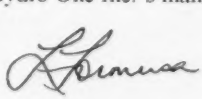
In meeting its responsibility for the reliability of financial information, management maintains and relies on a comprehensive system of internal control and internal audit. The system of internal control includes a written corporate conduct policy; implementation of a risk management framework; effective segregation of duties and delegation of authorities; and sound and conservative accounting policies that are regularly reviewed. This structure is designed to provide reasonable assurance that assets are safeguarded and that reliable information is available on a timely basis. In addition, internal and disclosure controls have been documented, evaluated, tested and identified consistent with National Instrument 52-109 (Bill 198). The effectiveness of these internal controls is evaluated and findings are reported to management and the Audit and Finance Committee of the Hydro One Board of Directors, as required.

The Consolidated Financial Statements have been examined by KPMG LLP, independent external auditors appointed by the Hydro One Board of Directors. The external auditors' responsibility is to express their opinion on whether the Consolidated Financial Statements are fairly presented in accordance with accounting principles generally accepted in Canada. The Independent Auditors' Report outlines the scope of their examination and their opinion.

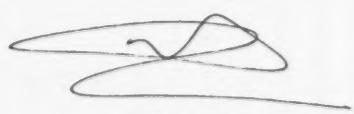
The Hydro One Board of Directors, through its Audit and Finance Committee, is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal controls. The Audit and Finance Committee of Hydro One met periodically with management, the internal auditors and the external auditors to satisfy itself that each group had properly discharged its respective responsibility and to review the Consolidated Financial Statements before recommending approval by the Board of Directors. The external auditors had direct and full access to the Audit and Finance Committee, with and without the presence of management, to discuss their audit and their findings as to the integrity of the financial reporting and the effectiveness of the system of internal controls.

The Company's President and Chief Executive Officer and Executive Vice-President and Chief Financial Officer have certified Hydro One's annual Consolidated Financial Statements and annual MD&A filed under provincial securities legislation, related disclosure controls and procedures and the design and effectiveness of related internal controls over financial reporting pursuant to National Instrument 52-109.

On behalf of Hydro One Inc.'s management:



Laura Formusa
President and Chief Executive Officer



Sandy Struthers
Executive Vice-President and Chief Financial Officer

HYDRO ONE INC.
INDEPENDENT AUDITORS' REPORT

To the Shareholder of Hydro One Inc.

We have audited the accompanying Consolidated Financial Statements of Hydro One Inc., which comprise the consolidated balance sheets as at December 31, 2011 and December 31, 2010, the consolidated statements of operations and comprehensive income, retained earnings, accumulated other comprehensive loss, and cash flows for the years then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these Consolidated Financial Statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of Consolidated Financial Statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these Consolidated Financial Statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the Consolidated Financial Statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the Consolidated Financial Statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the Consolidated Financial Statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the Consolidated Financial Statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the Consolidated Financial Statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the Consolidated Financial Statements present fairly, in all material respects, the consolidated financial position of Hydro One Inc. as at December 31, 2011 and December 31, 2010, and the results of its consolidated operations and its consolidated cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants, Licensed Public Accountants

Toronto, Canada
February 10, 2012

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

Year ended December 31 (Canadian dollars in millions, except per share amounts)	**2011**	**2010**
Revenues		
Transmission *(Note 16)*	1,389	1,307
Distribution *(Note 16)*	4,019	3,754
Other	63	63
	5,471	5,124
Costs		
Purchased power *(Note 16)*	2,628	2,474
Operation, maintenance and administration *(Note 16)*	1,092	1,078
Depreciation and amortization *(Note 3)*	616	583
	4,336	4,135
Income before financing charges and provision for payments in lieu of corporate income taxes	1,135	989
Financing charges *(Note 4)*	344	342
Income before provision for payments in lieu of corporate income taxes	791	647
Provision for payments in lieu of corporate income taxes *(Notes 5 and 16)*	150	56
Net income	641	591
Other comprehensive income	-	-
Comprehensive income	641	591
Basic and fully diluted earnings per common share *(Canadian dollars) (Note 15)*	6.228	5.727

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

Year ended December 31 (Canadian dollars in millions)	**2011**	**2010**
Retained earnings, January 1	2,354	1,791
Net income	641	591
Dividends *(Note 15)*	(168)	(28)
Retained earnings, December 31	2,827	2,354

CONSOLIDATED STATEMENTS OF ACCUMULATED OTHER COMPREHENSIVE LOSS

Year ended December 31 (Canadian dollars in millions)	**2011**	**2010**
Accumulated other comprehensive loss, January 1	(10)	(10)
Other comprehensive loss	-	-
Accumulated other comprehensive loss, December 31	(10)	(10)

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS

December 31 (Canadian dollars in millions)	2011	2010
Assets		
Current assets:		
Cash	-	33
Short-term investments	228	139
Accounts receivable (net of allowance for doubtful accounts - $18 million; 2010 - $25 million) *(Note 16)*	961	911
Regulatory assets *(Note 8)*	24	42
Materials and supplies	25	21
Future income tax assets *(Note 5)*	19	35
Other	20	8
	1,277	1,189
Fixed assets *(Note 6)*:		
Fixed assets in service	21,008	19,767
Less: Accumulated depreciation	7,679	7,247
	13,329	12,520
Construction in progress	1,436	1,394
Future use land, components and spares	138	139
	14,903	14,053
Other long-term assets:		
Regulatory assets *(Note 8)*	1,064	1,013
Deferred pension asset *(Note 12)*	466	460
Long-term investment	250	249
Intangible assets (net of accumulated amortization) *(Note 7)*	224	197
Goodwill	133	133
Future income tax assets *(Note 5)*	17	19
Other	34	9
	2,188	2,080
Total assets	18,368	17,322

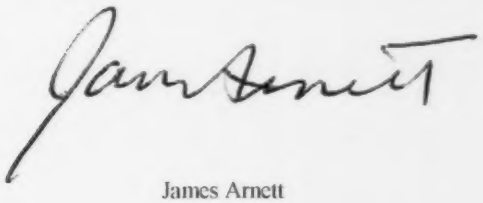
See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS (continued)

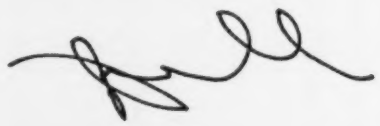
December 31 (Canadian dollars in millions)	2011	2010
Liabilities		
Current liabilities:		
Bank indebtedness	39	-
Accounts payable and accrued charges *(Notes 13 and 16)*	1,071	884
Regulatory liabilities *(Note 8)*	25	72
Accrued interest	85	84
Long-term debt payable within one year *(Note 9)*	600	500
	1,820	1,540
Long-term debt *(Note 9)*	7,399	7,278
Other long-term liabilities:		
Employee future benefits other than pension *(Note 12)*	1,040	980
Regulatory liabilities *(Note 8)*	635	540
Future income tax liabilities *(Note 5)*	758	693
Environmental liabilities *(Note 13)*	235	287
Asset retirement obligations *(Note 14)*	15	11
Long-term accounts payable and other liabilities	12	12
	2,695	2,523
Total liabilities	11,914	11,341
Contingencies and commitments *(Notes 18 and 19)*		
Shareholder's equity *(Note 15)*		
Preferred shares (authorized: unlimited; issued: 12,920,000)	323	323
Common shares (authorized: unlimited; issued: 100,000)	3,314	3,314
Retained earnings	2,827	2,354
Accumulated other comprehensive loss	(10)	(10)
Total shareholder's equity	6,454	5,981
Total liabilities and shareholder's equity	18,368	17,322

See accompanying notes to Consolidated Financial Statements.

On behalf of the Board of Directors:



James Arnett
Chair



Michael J. Mueller
Chair, Audit and Finance Committee

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31 (Canadian dollars in millions)	2011	2010
Operating activities		
Net income	641	591
Environmental expenditures	(16)	(17)
Adjustments for non-cash items:		
Depreciation and amortization (excluding removal costs)	550	526
Regulatory asset and liability accounts	47	(10)
Gain on interest rate swap agreements	(12)	(17)
Future income taxes	(12)	(8)
Asset retirement obligation	4	4
Other	9	1
	1,211	1,070
Changes in non-cash balances related to operations *(Note 17)*	196	94
Net cash from operating activities	1,407	1,164
Financing activities		
Long-term debt issued	700	1,500
Long-term debt retired	(500)	(600)
Short-term notes payable	-	(55)
Dividends paid	(168)	(28)
Other	(4)	-
Net cash from financing activities	28	817
Investing activities		
Capital expenditures		
Fixed assets	(1,371)	(1,557)
Intangible assets	(76)	(13)
	(1,447)	(1,570)
Long-term investments	-	(250)
Other assets	29	37
Net cash used in investing activities	(1,418)	(1,783)
Net change in cash and cash equivalents	17	198
Cash and cash equivalents, January 1	172	(26)
Cash and cash equivalents, December 31 *(Note 17)*	189	172

See accompanying notes to Consolidated Financial Statements.

1. DESCRIPTION OF THE BUSINESS

Hydro One Inc. (Hydro One or the Company) was incorporated on December 1, 1998, under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (the Province). The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario. These businesses are regulated by the Ontario Energy Board (OEB).

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Consolidation

The Consolidated Financial Statements include the accounts of the Company and its wholly-owned subsidiaries: Hydro One Networks Inc. (Hydro One Networks), Hydro One Remote Communities Inc. (Hydro One Remote Communities), Hydro One Brampton Networks Inc. (Hydro One Brampton), Hydro One Telecom Inc., Hydro One Lake Erie Link Management Inc. and Hydro One Lake Erie Link Company Inc.

Basis of Accounting

The Consolidated Financial Statements are prepared in accordance with accounting principles generally accepted in Canada.

Rate-setting

The rates of the Company's electricity transmission and distribution businesses are subject to regulation by the OEB.

Transmission

To achieve the necessary funding in support of required infrastructure, Hydro One Networks filed a transmission rate application for 2009 and 2010 rates in September 2008. The application sought OEB approval for revenue requirements of approximately $1,233 million and $1,341 million, based on returns on equity of 8.53% and 9.35% for 2009 and 2010, respectively. On May 28, 2009, the OEB issued its decision with reasons in respect of this application. The decision, which was effective July 1, 2009, resulted in reduced revenue requirements of $1,180 million and $1,240 million in 2009 and 2010, respectively, primarily due to a lower approved return on equity. The OEB decision disallowed development capital expenditures of $180 million for 2010, but agreed to reconsider the projects if additional evidence was provided. On September 4, 2009, Hydro One Networks filed the additional evidence on two projects amounting to approximately $160 million in capital expenditures. The OEB approved the supplemental evidence for inclusion in Hydro One Networks' 2010 rates. This resulted in a revised revenue requirement of $1,257 million for 2010, on the basis of an updated return on equity of 8.39% for 2010.

On May 19, 2010 Hydro One Networks submitted an application for 2011 and 2012 transmission rates in continued support of its aging critical infrastructure and the supply mix objectives for generation, including off-coal initiatives and initiation of investments in support of the Green Energy Act (GEA). This application sought the approval of revenue requirements of approximately $1,446 million for 2011 and $1,547 million for 2012.

On December 23, 2010, the OEB issued its decision with reasons effective January 1, 2011, which resulted in approved revenue requirements of $1,346 million for 2011 and $1,658 million for 2012. The approved 2012 revenue requirement was higher than that applied for, reflecting OEB direction to Hydro One to adopt a modified International Financial Reporting Standards (IFRS) cost capitalization policy. This adjustment was subsequently reversed by the OEB when it approved the use of United States (US) Generally Accepted Accounting Principles (GAAP) for rate-setting purposes beginning January 1, 2012.

Distribution

In late 2008, Hydro One Networks filed an incentive regulation application for 2009 rates, with an update filed in January 2009, to reflect the impact of a previous 2008 distribution rate decision. The application was filed on the basis of the OEB's third-generation Incentive Regulation Mechanism (IRM) process, which adjusts rates by considering inflation, productivity targets, significant events outside the control of management and a capital adjustment mechanism to recover costs for new incremental capital coming into service beyond a prescribed

threshold. On May 13, 2009, the OEB released its decision with reasons approving the basic IRM increase and a rate adder of $1.65 per month per metered customer for smart meters. The revised rates were approved effective May 1, 2009, with an implementation date of June 1, 2009.

In 2009, Hydro One Networks filed a cost-of-service application with the OEB for 2010 and 2011 distribution rates, reflecting the Company's plan to invest in its network assets to meet objectives regarding public and employee safety; regulatory and legislative compliance; maintenance of system security and reliability of system growth requirements; and investments required by the GEA. The application sought OEB approval of revenue requirements of approximately $1,150 million and $1,264 million for 2010 and 2011, respectively.

On April 9, 2010, the OEB released its decision with reasons approving revenue requirements of $1,146 million for 2010 and $1,236 million for 2011 to support the necessary work programs, the implementation of the GEA and the installation of smart meters. The OEB also approved certain distribution-related regulatory account balances sought by Hydro One Networks in its application, including retail settlement variance accounts, Regulatory Asset Recovery Account I, retail cost variance accounts and smart meters. The OEB ordered that the approved balances be aggregated into a single regulatory account (Rider 6) to be recovered over an 18-month period from May 1, 2010 to December 31, 2011.

On November 7, 2008, Hydro One Brampton filed an application for 2009 rates on the basis of the OEB's second-generation IRM policy. On March 13, 2009, the OEB released it decision with reasons. The revised rates, including an adder of $1 per month per metered customer for smart meters, were approved for implementation effective May 1, 2009.

On November 6, 2009, Hydro One Brampton filed an application for 2010 distribution rates on the basis of the OEB's second-generation IRM process. On April 13, 2010, the OEB released its decision regarding this rate application approving Hydro One Brampton's submission on the basis of the OEB's cost-of-capital and second-generation IRM policies. The revised rates had an implementation date of May 1, 2010.

On June 30, 2010, Hydro One Brampton submitted a 2011 cost-of-service application, which was subsequently adjusted on September 2, 2010 to reflect the deferral of the adoption of modified IFRS until January 1, 2012. The updated submission was filed on November 8, 2010 and requested OEB approval for a revenue requirement of approximately $63 million. On April 4, 2011, the OEB issued a decision with reasons that reduced the requested revenue requirement. This reduction included the impact of reductions to operation, maintenance and administration costs. The revised rates were approved with an effective date of January 1, 2011 and an implementation date of May 1, 2011. Included in the rates is an adder of $1.52 per month per metered customer for smart meters and approval of a GEA funding adder of $0.02 per month per metered customer.

On November 4, 2009, Hydro One Remote Communities filed an application for 2010 distribution rates under the OEB's third-generation IRM, seeking approval of an increase to basic rates for the distribution and generation of electricity. The increase reflects the standard inflationary adjustments incorporated in the third-generation IRM applications. On April 14, 2010, the OEB issued a decision with reasons regarding this rate application, approving revised rates with an effective date and implementation date of May 1, 2010.

On October 15, 2010, Hydro One Remote Communities filed an application for 2011 distribution rates on the basis of the OEB's third-generation IRM seeking approval for an increase of approximately 0.4% to basic rates for the distribution and generation of electricity effective May 1, 2011. On March 28, 2011, the OEB issued its decision with reasons approving the application. The revised rates were approved with an effective date and implementation date of May 1, 2011.

Regulatory Accounting

The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. Such change in timing involves the application of rate-regulated accounting, giving rise to the recognition of regulatory assets and liabilities. The Company's regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities which

represent amounts for expenses incurred in different periods than would be the case had the Company been unregulated. The Company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will factor its regulatory assets and liabilities into the setting of future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in future rates, the appropriate carrying amount will be reflected in results of operations in the period that the assessment is made. Specific regulatory assets and liabilities are disclosed in Note 8.

Revenue Recognition and Allocation

Transmission revenues are collected through OEB-approved rates, which are based on an approved revenue requirement that includes a rate of return. Such revenue is recognized as power is transmitted and delivered to customers.

Distribution revenues attributable to the delivery of electricity are based on OEB-approved distribution rates and are recognized as electricity is delivered to customers. The Company estimates the monthly revenue for the period based on wholesale power purchases because customer meters are not generally read at the end of each month. Unbilled revenue included within accounts receivable as at December 31, 2011 amounted to $544 million (2010 - $493 million).

Distribution revenue also includes an amount relating to rate protection for rural residential and remote customers, which is received from the Independent Electricity System Operator (IESO) based on a standardized customer rate that is approved by the OEB. The current legislation provides rate protection for prescribed classes of rural residential and remote consumers by reducing the electricity rates that would otherwise apply.

Segment revenues for transmission, distribution and other also include revenue related to sales of other services and equipment. Such revenue is recognized as services are rendered or as equipment is delivered.

Corporate Income and Capital Taxes

Under the *Electricity Act, 1998*, Hydro One is required to make payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation (OEFC). These payments are calculated in accordance with the rules for computing income and taxable capital and other relevant amounts contained in the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario) (*Corporations Tax Act* (Ontario), prior to 2009) as modified by the *Electricity Act, 1998*, and related regulations.

Current Income Taxes

The provision for current taxes and the assets and liabilities recognized for the current and prior periods are measured at the amounts receivable or payable from/to the OEFC.

Future Income Taxes

Future income taxes are provided for using the liability method and are recognized on temporary differences between the carrying amount of assets and liabilities in the Consolidated Financial Statements and the corresponding tax bases used in the computation of taxable profit.

Future income tax liabilities are generally recognized on all taxable temporary differences and future tax assets are recognized to the extent that it is more likely than not that they will be realized from taxable profits available against which deductible temporary differences can be utilized.

Future income taxes are calculated at the tax rates that are expected to apply in the period when the liability is settled or the asset is realized, based on the tax rates (and tax laws) that have been enacted or substantively enacted by the balance sheet date. Future income taxes are charged or credited to the Consolidated Statement of Operations and Comprehensive Income.

The carrying amount of future income tax assets is reviewed at each balance sheet date and reduced to the extent that all or part of the future income tax assets have not met the "more likely than not" criterion. Previously

unrecognized future income tax assets are reassessed at each balance sheet date and are recognized to the extent that it has become more likely than not that they will be recovered from future taxable profits.

The Company has recognized regulatory assets and liabilities which correspond to future income tax liabilities and assets that are expected to be recovered from or repaid to the customers in the rate-setting process.

Materials and Supplies

Materials and supplies represent consumables, spare parts and construction material held for internal construction and maintenance of fixed assets. These assets are carried at the lower of average cost or net realizable value.

Fixed Assets

Fixed assets are capitalized at cost, which comprises materials, labour, engineering, overheads, depreciation on service equipment and the OEB-approved allowance for funds used during construction applicable to capital construction activities within regulated businesses, or interest applicable to capital construction activities within unregulated businesses.

Fixed assets in service consist of transmission, distribution, communication, administration and service assets and easements. Fixed assets also include future use assets such as land; major components and spare parts; and capitalized development costs associated with deferred capital projects.

Transmission

Transmission assets include assets used for the transmission of high-voltage electricity such as transmission lines; support structures; foundations; insulators; connecting hardware and grounding systems; and assets used to step up the voltage of electricity from generating stations for transmission and to step down voltages for distribution, such as transformers, circuit breakers and switches.

Distribution

Distribution assets comprise assets related to the distribution of low-voltage electricity, including lines, poles, switches, transformers, protective devices and metering systems.

Communication

Communication assets include the fibre-optic and microwave radio system, optical ground wire, towers, telephone equipment and associated buildings.

Administration and Service

Administration and service assets include administrative buildings, major computer systems, personal computers, transport and work equipment, tools, vehicles and other minor fixed assets.

Easements

Easements include statutory rights of use for transmission corridors and abutting lands granted under the *Reliable Energy and Consumer Protection Act, 2002*, as well as other amounts related to land access rights.

Intangible Assets

Intangible assets represent computer applications software and other assets. These assets are capitalized at cost, which comprise materials, purchased software, labour and consulting, engineering, overheads and the OEB-approved allowance for funds used during construction applicable to capital activities within regulated businesses, or interest applicable to capital activities within unregulated businesses.

Construction and Development in Progress

Overhead costs, including shared corporate functions and services costs, are capitalized on a fully allocated basis, consistent with an OEB-approved methodology. Financing costs are capitalized on rate-regulated fixed assets under

construction and intangible assets under development, based on the OEB's approved allowance for funds used during construction (2011 - 4.20%; 2010 - 4.34%).

Depreciation and Amortization

The capital costs of fixed and intangible assets primarily consisting of applications software, are depreciated or amortized on a straight-line basis, except for transport and work equipment, which is depreciated on a declining balance basis.

The Company periodically initiates an external review of its fixed asset and intangible asset depreciation and amortization rates, as required by the OEB. The last review resulted in changes to rates effective January 1, 2007. A summary of depreciation and amortization rates for the various classes of assets is included below:

	Depreciation and amortization rates (%)	
	Range	Average
Transmission	1% - 3%	2%
Distribution	1% - 13%	2%
Communication	1% - 13%	5%
Administration and service	1% - 20%	8%

The costs of intangible assets are primarily included within the administration and service classification above and these assets are amortized on a straight-line basis. Amortization rates for computer applications software and other intangible assets range from 9% to 11%.

Depreciation rates for easements are based on their contract lives. The majority of easements are held in perpetuity and are not depreciated.

In accordance with group depreciation practices, the original cost of fixed and intangible assets that are normally retired is charged to accumulated depreciation or amortization, with no gain or loss reflected in current results of operations. Gains and losses on sales of fixed assets and losses on premature retirements are charged to results of operations as adjustments to depreciation or amortization expense. Depreciation expense also includes the costs incurred to remove fixed assets where no asset retirement obligation has been recorded.

The estimated service lives of fixed or intangible assets are subject to periodic review. Any changes arising from such a review are implemented on a remaining service life basis consistent with their inclusion in electricity rates.

Goodwill

Goodwill represents the cost of acquired local distribution companies in excess of fair value of the net identifiable assets purchased and is evaluated for impairment on an annual basis, or more frequently if circumstances require. Goodwill impairment is assessed based on a comparison of the fair value of the reporting unit to the underlying carrying value of the reporting unit's net assets, including goodwill, with any write-down of the carrying value of goodwill being charged against the results of operations. The Company has determined that goodwill is not impaired. All of the goodwill is attributable to the Distribution Business segment.

Financial Instruments

Recognition and Measurement

All financial instruments are classified into one of the following five categories: held-to-maturity investments; loans and receivables; held-for-trading; other liabilities; or available-for-sale. All financial instruments, including derivatives, are carried at fair value on the Consolidated Balance Sheet, except for loans and receivables, held-to-maturity investments and other financial liabilities, which are measured at amortized cost. Held-for-trading financial instruments are measured at fair value and all gains and losses are included in financing charges in the period in which they arise. Available-for-sale financial instruments are measured at fair value with revaluation gains and losses included in other comprehensive income (OCI) until the instrument is derecognized or impaired. The Company has classified its financial instruments as follows:

Assets / Liabilities	Classification	Measurement
Cash	Held-for-trading	Fair value
Accounts receivable	Loans and receivables	Amortized cost
Short-term investments	Held-to-maturity / Held-for-trading	Amortized cost / fair value
Long-term investment	Held-to-maturity	Amortized cost
Bank indebtedness	Other liabilities	Amortized cost
Accounts payable	Other liabilities	Amortized cost
Short-term notes payable	Other liabilities	Amortized cost
Long-term debt (unless otherwise specified)	Other liabilities	Amortized cost
Fixed-to-floating interest-rate swaps	Not classified	Fair value
Medium-Term Note (MTN) Series 14 Note	Not classified	Fair value
$500 million of MTN Series 19 Note	Not classified	Fair value
$250 million of MTN Series 21 Note	Not classified	Fair value
Floating-to-fixed interest-rate swaps	Held-for-trading	Fair value

Short-term investments are generally classified as held-to-maturity. However, certain short-term investments are classified as held-for-trading when the Company has no intent to hold a pool of assets to their maturity. Documentation of the short-term investment classification is made on inception.

Certain tranches of long-term debt are designated as part of a hedging relationship, as in the case of the MTN Series 14 Note, $500 million of the MTN Series 19 Note and $250 million of the MTN Series 21 Note. These long-term debt, and related hedging instruments, are not classified.

All financial instrument transactions are recorded at trade date.

Discounts and Premiums on Debt

Discounts and premiums are amortized over the period of the related debt using the effective interest method.

Transaction Costs

Transaction costs for financial assets and liabilities that are classified as other than held-for-trading are added to the carrying value of the asset or liability and then amortized over the expected life of the instrument using the effective interest method.

Derivative Instruments and Hedge Accounting

All derivative instruments, including embedded derivatives, are carried at fair value on the Consolidated Balance Sheet unless exempted from derivative treatment as a normal purchase and sale or when it is deemed that the economic characteristics and risks of the embedded derivative are not closely related to the economic characteristics and risks of the host contract. The Company does not have any significant embedded derivatives in contracts that require separate accounting and disclosure.

All changes in fair value are recorded in financing charges unless cash flow hedge accounting is used, in which case changes in fair value are recorded in OCI to the extent that the hedge is effective. The gain or loss related to the ineffective portion, if any, is recorded in financing charges.

The Company does not engage in derivative trading or speculative activities.

The Company periodically develops hedging strategies for execution taking into account risk management objectives. At the inception of a hedging relationship, the Company formally documents the hedging relationship between the hedged item and the hedging instrument, its risk management objective for establishing the hedging relationship, the nature of the specific risk exposure being hedged, and the method for assessing effectiveness of the hedging relationship. The Company also assesses, both at the inception of the hedge and on an ongoing basis, whether the hedging items that are used are effective in offsetting changes in fair values or cash flows of the hedged items.

Comprehensive Income

Comprehensive income is comprised of the Company's net income and OCI. OCI includes the amortization of net unamortized hedging losses on discontinued cash flow hedges and the change in fair value on existing cash flow hedges to the extent that the hedge is effective. The Company amortizes its unamortized hedging losses on discontinued cash flow hedges to financing charges using the effective interest method over the term of the hedged debt.

Financial Instrument Disclosures

All financial instruments measured at fair value are categorized into one of the three levels of hierarchy. Each level is based on the transparency of the inputs used to measure the fair values of assets and liabilities:

Level 1 – inputs are unadjusted quoted prices of identical instruments in an active market;
Level 2 – inputs do not have quoted prices but are observable for the asset or liability, either directly or indirectly; and
Level 3 – inputs that are not based on observable market data.

The fair market value of the Company's long-term debt is determined using the fair value hierarchy levels disclosed in Note 10.

Employee Future Benefits

Employee future benefits provided by Hydro One include pension, group life insurance, health care and long-term disability.

In accordance with the OEB's rate orders, pension costs are recorded when employer contributions are paid to the pension fund in accordance with the *Pension Benefits Act* (Ontario). Actuarial valuations are conducted at least every three years. Pension costs are also calculated on an accrual basis. Pension costs are actuarially determined using the projected benefit method prorated on service and based on assumptions that reflect management's best estimate of the effect of future events, including future compensation increases, on the actuarial present value of accrued pension benefits. Pension plan assets, consisting primarily of listed equity securities as well as corporate and government debt securities, are valued using fair values. Past service costs from plan amendments and all actuarial gains or losses are amortized on a straight-line basis over the expected average remaining service life of the employees covered.

Employee future benefits other than pension are recorded on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. Past service costs from plan amendments and actuarial gains or losses are amortized on a straight-line basis over the expected average remaining service life of the employees covered.

Employee future benefit costs are attributed to labour and charged to operations or capitalized as part of the cost of fixed and intangible assets.

Environmental Costs

Hydro One records a liability for the estimated future expenditures associated with the assessment and remediation of contaminated lands and for the phase-out and destruction of polychlorinated biphenyls (PCB) contaminated mineral oil removed from electrical equipment, based on the present value of these estimated future expenditures. As the Company anticipates that the related expenditures will continue to be recoverable in future rates, a regulatory asset has been recorded to reflect the future recovery of these costs from customers. Hydro One reviews its estimates of future environmental expenditures on an ongoing basis.

Asset Retirement Obligations

When required by force of law or regulation, Hydro One records an asset retirement obligation based on the present value of the estimated fair value expenditures to remove certain assets and mitigate related sites. Where the Company anticipates that the related expenditures will be recoverable in future rates, a corresponding amount is capitalized as a cost of the related fixed assets. Some of the Company's transmission and distribution assets,

particularly those located on unowned easements and rights-of-way, may have asset retirement obligations, conditional or otherwise. The majority of the Company's easements and rights-of-way are either of perpetual duration or are automatically renewed annually. Land rights with finite terms are generally subject to extension or renewal. As the Company expects to use the majority of its facilities in perpetuity, no asset retirement obligation currently exists. If, at some future date, a particular facility is shown not to meet the perpetuity criterion, it will be reviewed to determine whether a measurable asset retirement obligation exists. In such a case, an asset retirement obligation would be recorded at that time. The asset retirement obligations recorded to date are primarily related to the estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of the Company's facilities and the decommissioning of certain switching stations.

Use of Estimates

The preparation of Consolidated Financial Statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the Consolidated Financial Statements, and the reported amounts of revenues and expenses for the year. Actual results could differ from estimates, including changes as a result of future decisions made by the OEB or the Province.

Emerging Accounting Changes

US GAAP

The Company previously anticipated it would apply IFRS to its Consolidated Financial Statements for fiscal periods beginning on or after January 1, 2012, with comparative restatement of the amounts recorded on the opening IFRS balance sheet as at January 1, 2011. In the absence of a definitive plan for a new project to consider the issuance of a rate-regulated accounting standard by the International Accounting Standards Board, Hydro One began evaluating the option of adopting US GAAP in lieu of IFRS in the first quarter of 2011. On July 7, 2011, the Company filed an application with the OSC for exemptive relief from the requirements of section 3.2 of National Instrument 52-107 *Acceptable Accounting Policies and Auditing Standards* that would otherwise require it to file Consolidated Financial Statements based on IFRS starting with reporting periods commencing after January 1, 2012. The Company's application requested approval to instead adopt US GAAP, without becoming a Securities and Exchange Commission registrant, for its 2012, 2013 and 2014 fiscal years. On July 21, 2011, the OSC approved the Company's application and granted it the requested exemptive relief. Hydro One's Board of Directors has approved a resolution authorizing it to report under US GAAP. As a result, the Company's March 31, 2012 Consolidated Financial Statements will be prepared based on US GAAP with one year of comparative restatement. The Company's opening US GAAP Consolidated Balance Sheet as at January 1, 2010 will be based on a retrospective application of US GAAP. The Company anticipates that its current application of Canadian GAAP for rate-regulated activities will generally be consistent with US GAAP. Any differences between Canadian and US GAAP and their impact on the Company's Consolidated Financial Statements will be assessed as part of the Company's US GAAP conversion project.

3. DEPRECIATION AND AMORTIZATION

Year ended December 31 (Canadian dollars in millions)	2011	2010
Depreciation of fixed assets in service	485	456
Amortization of intangible assets	45	43
Fixed asset removal costs	66	57
Amortization of regulatory and other assets	20	27
	616	583

4. FINANCING CHARGES

Year ended December 31 (Canadian dollars in millions)	2011	2010
Interest on long-term debt payable	412	409
Amortization of debt issuance costs	3	3
Other	5	7
Less: Interest capitalized on construction and development in progress	(58)	(54)
Gain on interest-rate swap agreements	(12)	(17)
Net amortization of premiums	(3)	(3)
Interest earned on investments	(3)	(3)
	344	342

5. PROVISION FOR PAYMENTS IN LIEU OF CORPORATE INCOME TAXES

The provision for payments in lieu of corporate income taxes (PILs) differs from the amount that would have been recorded using the combined Canadian Federal and Ontario statutory income tax rate. The reconciliation between the statutory and effective tax rates is provided as follows:

(Canadian dollars in millions)	2011	2010
Income before provision for PILs	791	647
Federal and Ontario statutory income tax rate	28.25%	31.00%
Provision for PILs at statutory rate	223	201
Increase (decrease) resulting from:		
Net temporary differences included in amounts charged to customers:		
Capital cost allowance in excess of depreciation and amortization	(34)	(82)
Pension contributions in excess of pension expense	(17)	(18)
Overheads capitalized for accounting but deducted for tax purposes	(12)	(13)
Interest capitalized for accounting but deducted for tax purposes	(16)	(17)
Employee future benefits other than pension expense in excess of cash payments	5	3
Environmental expenditures	(4)	(5)
Other	3	(15)
Net temporary differences	(75)	(147)
Net permanent differences	2	2
Total income tax provision for PILs	150	56
Current income tax provision for PILs	162	64
Future income tax provision for PILs	(12)	(8)
Total income tax provision for PILs	150	56
Effective income tax rate	18.96%	8.66%

The provision for payments in lieu of current income taxes of $162 million represents the amount payable to the OEFC with respect to current year earnings. The outstanding balance due to the OEFC at December 31, 2011 is $85 million (2010 - $17 million).

The payments in lieu of future income taxes recoverable of $12 million reflects the decrease in the liability for payments in lieu of future income taxes that are not expected to be recovered from the Company's customers through future rates. The increase in the liability for payments in lieu of future income taxes that is expected to be recovered from the Company's customers through future rates has resulted in an increase in regulatory assets.

Future Income Tax Assets and Liabilities

Payments in lieu of future income tax assets and liabilities arise from differences between the carrying amounts and tax bases of the Company's assets and liabilities. The tax effects of these differences are as follows:

December 31 (Canadian dollars in millions)	2011	2010
Future income tax assets		
Depreciation and amortization in excess of capital cost allowance	6	9
Employee future benefits other than pension expense in excess of cash payments	5	5
Environmental expenditures	5	3
Other	1	5
Total future income tax assets	17	22
Less: current portion	-	3
	17	19

December 31 (Canadian dollars in millions)	2011	2010
Future income tax liabilities		
Capital cost allowance in excess of depreciation and amortization	(1,106)	(1,004)
Employee future benefits other than pension expense in excess of cash payments	356	337
Environmental expenditures	61	76
Transmission and Distribution amounts received but not recognized for accounting purposes	(46)	(69)
Goodwill	(18)	(17)
Retail settlement variance accounts	10	5
Other	5	11
Total future income tax liabilities	(739)	(661)
Less: current portion	19	32
	(758)	(693)

As at December 31, 2011, payments in lieu of future income tax assets of $608 thousand (2010 - $574 thousand), based on substantively enacted income tax rates and laws, have not been recorded, as it is more likely than not that the assets will not be realized in the future.

6. FIXED ASSETS

December 31 (Canadian dollars in millions)	Fixed Assets	Accumulated Depreciation	Construction in Progress	Total
2011				
Transmission	10,906	3,810	1,079	8,175
Distribution	7,596	2,706	253	5,143
Communication	919	468	43	494
Administration and service	1,232	607	61	686
Easements	493	88	-	405
	21,146	7,679	1,436	14,903
2010				
Transmission	10,204	3,626	1,070	7,648
Distribution	7,230	2,556	262	4,936
Communication	892	426	37	503
Administration and service	1,089	554	25	560
Easements	491	85	-	406
	19,906	7,247	1,394	14,053

Financing costs are capitalized on fixed assets under construction, including allowance for funds used during construction on regulated assets and interest on unregulated assets, and were $57 million in 2011 (2010 - $54 million).

7. INTANGIBLE ASSETS

December 31 (Canadian dollars in millions)	Intangible Assets	Accumulated Amortization	Development in Progress	Total
2011				
Computer applications software	427	254	49	222
Other assets	5	3	-	2
	432	257	49	224
2010				
Computer applications software	395	209	9	195
Other assets	5	3	-	2
	400	212	9	197

Financing costs are capitalized on intangible assets under development, including allowance for funds used during development of regulated assets, and were $1 million in 2011 (2010 - $nil).

8. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-setting process. Hydro One has recorded the following regulatory assets and liabilities:

December 31 (Canadian dollars in millions)	2011	2010
Regulatory assets:		
Regulatory future income tax asset	763	674
Environmental	257	309
Pension cost variance account	42	27
Rider 2 (Regulatory asset recovery account II)	11	11
Long-term project development cost account	5	7
Rural and remote rate protection variance account	-	7
Rider 4 (Revenue recovery account)	-	5
Other	10	15
Total regulatory assets	1,088	1,055
Less: current portion	24	42
	1,064	1,013

	2011	2010
Regulatory liabilities:		
Deferred pension	466	460
Rider 8	41	9
External revenue variance account	39	29
Retail settlement variance accounts	39	22
Regulatory future income tax liability	25	30
Rider 3 (Regulatory liability refund account)	9	19
PST savings deferral account	8	4
Rural and remote rate protection variance account	8	-
Hydro One Brampton rider	2	6
Rider 6	-	19
Other	23	14
Total regulatory liabilities	660	612
Less: current portion	25	72
	635	540

Regulatory Assets

Regulatory Future Income Tax Asset and Liability

Future income taxes are recognized on temporary differences between the carrying amount of assets and liabilities in the Consolidated Financial Statements and the corresponding tax bases used in the computation of taxable profit. The Company has recognized regulatory assets and liabilities which correspond to future income taxes that flow through the rate-setting process. In the absence of rate-regulated accounting, the Company's provision for PILs would have been recognized using the liability method and there would be no regulatory accounts established for taxes to be recovered through future rates. As a result, the provision for PILs would have been higher by approximately $70 million (2010 - $104 million), including the impact of a change in substantively enacted tax rates.

Environmental

Hydro One records a liability for the estimated future expenditures required to remediate past environmental contamination (see Note 13). Because such expenditures are expected to be recoverable in future rates, the Company has recorded an equivalent amount as a regulatory asset. In 2011, this regulatory asset decreased by $55 million (2010 - decreased by $15 million) to reflect related changes in the Company's PCB liability and increased by $5 million (2010 - decreased by $1 million) for changes in the land assessment and remediation (LAR) liability. The environmental regulatory asset is amortized to results of operations based on the pattern of actual expenditures incurred. The OEB has the discretion to examine and assess the prudence and the timing of recovery of all of Hydro

One's actual environmental expenditures. In the absence of rate-regulated accounting, operation, maintenance and administration expenses would have been lower by $50 million (2010 - $16 million). In addition, amortization expense in 2011 would have been lower by $16 million (2010 - $17 million) and financing charges would have been higher by $14 million (2010 - $15 million).

Pension Cost Variance Account

The pension cost variance account was established for Hydro One Networks' Transmission and Distribution businesses to track the difference between the actual pension costs incurred by the Company and estimated pension costs approved by the OEB. The balance in this account reflects the difference between pension costs paid compared to OEB-approved amounts. On May 28, 2009, the OEB announced its decision regarding the Company's rate application in respect of the Transmission Business of Hydro One Networks for 2009 and 2010 rates. As part of this decision, the OEB approved recovery of the proposed balance in this account plus accrued interest for recovery over 18 months ending December 31, 2010. In the December 23, 2010 decision on 2011 and 2012 transmission rates, the OEB approved the December 31, 2009 balance, including accrued interest, to be recovered over a one-year period from January 1, 2011 to December 31, 2011. In the absence of rate-regulated accounting, revenue would have been lower by $14 million in 2011 (2010 - $20 million).

Rider 2 or Regulatory Asset Recovery Account II

On April 12, 2006, the OEB announced its decision regarding the Company's rate application in respect of the Distribution Business of Hydro One Networks. As part of this decision, the OEB also approved the distribution-related regulatory account balances sought by Hydro One. Rider 2 includes retail settlement and cost variance amounts and distribution low-voltage service amounts, plus accrued interest. In the absence of rate-regulated accounting, amortization expense in 2011 would have remained unchanged (2010 - lower by $8 million). In addition, related financing charges would have remained the same in both years.

Long-term Project Development Cost Account

On May 28, 2009 the OEB approved the creation of a deferral account to record Hydro One's costs of preliminary work to advance certain transmission projects identified in its 2009 and 2010 transmission rate application. On March 25, 2010, the OEB issued a decision amending the scope of the account to include the 20 major transmission projects identified in the September 21, 2009 request from the then Minister of Energy and Infrastructure. In its December 23, 2010 decision, the OEB approved the recovery of the December 31, 2009 balance, including accrued interest, over a one-year period from January 1, 2010 to December 31, 2011. The Company anticipates that it will seek recovery for the remaining balance in its next transmission rate application. In the absence of rate-regulated accounting, operation, maintenance and administration expenses would have been lower by $2 million (2010 - higher by $5 million).

Rural and Remote Rate Protection Variance Account (RRRP)

Hydro One receives rural rate protection amounts from the IESO. A portion of these amounts is provided to retail customers of Hydro One Networks who are eligible for rate protection. In 2002, the OEB approved a mechanism to collect the RRRP through the Wholesale Market Service Charge. Variances between the amounts remitted by the IESO to Hydro One and the fixed entitlements defined in the regulation, and subsequent OEB utility rate decisions, are tracked by the Company in the RRRP variance account to be disposed of at a later date.

Rider 4 or Revenue Recovery Account

On December 18, 2008, the OEB announced its decision regarding the Company's rate application in respect of the Distribution Business of Hydro One Networks. The approved rates were effective May 1, 2008 with an implementation date of February 1, 2009. The OEB approved the establishment of Rider 4 to record the revenue differential between existing distribution rates and the new rates. The OEB ordered that the approved revenue requirement be retroactively recovered, through a rate rider, over a period of 27 months commencing February 1, 2009 and ending April 30, 2011.

Regulatory Liabilities

Deferred Pension

In accordance with the OEB's 1999 transitional rate order, pension costs are recorded in results of operations when employer contributions are paid into the pension plan. The Company's deferred pension asset represents the cumulative difference between employer contributions and pension costs and the deferred pension regulatory liability results from the Company's recognition, as the result of OEB direction, of revenues and expenses in different periods than would be the case for an unregulated enterprise. In the absence of rate-regulated accounting, operating, maintenance and administration expense would have been lower by $3 million (2010 - $22 million).

Rider 8

As part of the April 9, 2010 decision, the OEB also requested the establishment of deferral accounts which capture the difference between the revenue recorded on the basis of Green Energy Plan expenditures incurred and actual recoveries received.

External Revenue Variance Account

In its May 28, 2009 decision, the OEB approved forecasted amounts related to export service revenue, external revenue from secondary land use and external revenue from station maintenance and engineering and construction work. These revenue sources are an offset to the Company's revenue requirement, and as such, the OEB requested the establishment of new variance accounts to capture any difference between the approved forecast and actual revenues from these sources of external revenue. The balance reflects the excess of external revenue compared to the OEB-approved forecast. The OEB's December 23, 2010 decision approved the disposition of the December 31, 2009 balance, including accrued interest, over a one-year period from January 1, 2011 to December 31, 2011.

Retail Settlement Variance Accounts (RSVA)

Hydro One has deferred certain retail settlement variance amounts under the provisions of Article 490 of the OEB's *Accounting Procedures Handbook*. The OEB's December 18, 2008 decision allowed for the disposition of RSVA accumulated since May 1, 2006 through to April 30, 2008, inclusive of interest, within the Regulatory Liability Refund Account (RLRA). Hydro One Networks accumulated a net liability in its RSVA from May 1, 2008 to December 31, 2009. On April 9, 2010, the OEB announced its decision regarding Hydro One Networks' distribution rate application which included the allowance to dispose of RSVA accumulated during that period, inclusive of interest, within Rider 6. Hydro One Networks has accumulated a net liability in its RSVA account since December 31, 2009.

Rider 3 or RLRA

The OEB's December 18, 2008 decision approved certain distribution-related deferral account balances sought by Hydro One in its application including RSVA amounts, deferred tax changes, OEB costs and smart meters. Amounts approved for recovery represented balances incurred prior to April 30, 2008, plus associated interest. The OEB ordered that the approved balances be aggregated into a single regulatory account to be recovered over a 27-month period from February 1, 2009 to April 30, 2011.

PST savings deferral account

The amounts recognized in this regulatory account reflect the impact on the Company from the implementation of an HST sales tax regime on July 1, 2010. The variance recognized is the amount approved in the revenue requirement relating to the previous Provincial Sales Tax (PST) regime. The PST savings are refundable to ratepayers in future years.

Hydro One Brampton Rider

On April 13, 2010, the OEB issued a decision regarding the 2010 distribution rates of Hydro One Brampton. Included in the OEB's decision was the approval of certain deferral account balances, primarily RSVA, sought by Hydro One Brampton in its application. The OEB ordered that the approved balances be aggregated into a single regulatory account to be disposed of through a rate rider over a two-year period from May 1, 2010 to April 30, 2012.

Rider 6

As part of the April 9, 2010 decision, the OEB approved certain distribution-related deferral account balances sought by Hydro One in its application including retail settlement variance accounts, regulatory asset recovery account I, retail cost variance accounts and smart meters. The OEB ordered that the approved balances be aggregated into a single regulatory account to be recovered over an 18-month period from May 1, 2010 to December 31, 2011.

9. DEBT

December 31 (Canadian dollars in millions)	2011	2010
Long-term debt:		
4.08% notes due 2011[1]	-	250
6.40% notes due 2011	-	250
5.77% notes due 2012	600	600
5.00% notes due 2013	600	600
3.13% notes due 2014[1]	750	750
2.95% notes due 2015[1]	500	250
Floating-rate notes due 2015	50	-
4.64% notes due 2016	450	450
5.18% notes due 2017	600	600
4.40% notes due 2020	300	300
7.35% debentures due 2030	400	400
6.93% notes due 2032	500	500
6.35% notes due 2034	385	385
5.36% notes due 2036	600	600
4.89% notes due 2037	400	400
6.03% notes due 2039	300	300
5.49% notes due 2040	500	500
4.39% notes due 2041	300	-
6.59% notes due 2043	315	315
5.00% notes due 2046	325	325
4.00% notes due 2051	100	-
	7,975	7,775
Add: Unrealized marked-to-market loss[1]	33	8
Less: Long-term debt payable within one year	(600)	(500)
Net unamortized premiums	23	27
Unamortized debt issuance costs	(32)	(32)
Long-term debt	7,399	7,278

[1] The unrealized marked-to-market loss relates to the MTN Series 14 Note which matured on March 3, 2011; $500 million of the MTN Series 19 Note which will mature on November 14, 2014 and $250 million of the MTN Series 21 Note issued in January 2011 which will mature on September 11, 2015 which are all accounted for as fair value hedges. The unrealized marked-to-market loss is offset by a $33 million (2010 - $8 million) unrealized marked-to-market gain on the related fixed-to-floating interest-rate swap agreements.

Short-term debt represents promissory notes pursuant to the Company's Commercial Paper Program. The notes are denominated in Canadian dollars with varying maturities not exceeding 365 days. There was no short-term debt outstanding as of December 31, 2011 and December 31, 2010.

Hydro One has a $1,250 million committed and unused revolving standby credit facility with a syndicate of banks maturing in June 2014. If used, interest on the facility would apply based on Canadian benchmark rates. This credit facility supports the Company's Commercial Paper Program. In addition, the Company holds $250 million of Province of Ontario Floating Rate Notes as an alternative source of liquidity.

The Company issues notes for long-term financing under the Medium-Term Note (MTN) Program. The maximum authorized principal amount of medium-term notes issuable under this program is $3,000 million, of which $2,600 million was remaining and available as at December 31, 2011.

On August 2, 2011, the Company entered into two forward-rate agreements to lock in two interest-rate resets on the floating rate it pays on $50 million and $115 million of floating-rate debt with settlement dates of October 24 and November 21, 2011, respectively. The cash settlements on the forward rate agreements that settled on October 24 and November 21 were insignificant.

On November 16, 2011, the Company entered into two floating-to-fixed interest-rate swaps for $250 million each to lock in the floating rate it pays on (i) a $250 million fixed-to-floating interest-rate swap from December 12, 2011 to December 11, 2012 and (ii) a $250 million fixed-to-floating interest-rate swap from February 21, 2012 to February 19, 2013. On the same date it also entered into a floating-to-fixed interest-rate swap for $50 million to lock in the floating rate it pays on $50 million floating-rate notes from January 24, 2012 to January 24, 2013. The Company designated these swaps as fair value hedges of interest-rate risk. As such, changes in fair value are recognized in the Consolidated Statement of Operations for the period.

On December 22, 2011, the Company issued $100 million 4.00% notes under its MTN program with a maturity date of December 22, 2051.

The long-term debt is unsecured and denominated in Canadian dollars. Such debt is summarized by the number of years to maturity in Note 10.

10. CARRYING AND FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The carrying value of financial instruments as at December 31, 2011 is as follows:

(Canadian dollars in millions)	Derivatives Used for Hedging	Other Financial Instruments Used for Hedging	Held-for-Trading	Loans and Receivables	Other Financial Liabilities
Financial Assets					
Accounts receivable	-	-	-	961	-
Short-term investments	-	-	228	-	-
Long-term investment	-	-	250	-	-
Other assets	33	-	-	2	-
Financial Liabilities					
Bank indebtedness	-	-	-	-	39
Accounts payable and accrued charges[1]	-	-	-	-	976
Long-term debt	-	783	-	-	7,216

[1] Accounts payable and accrued charges do not include income taxes payable or dividends payable.

The carrying amounts of all financial instruments, except long-term debt, approximate fair value. The fair value of derivative financial instruments reflects the estimated amount that the Company, if required to settle an outstanding contract, would have been required to pay or would be entitled to receive at year end. The fair value of long-term debt, provided in the table below, is based on unadjusted year-end market prices for the same or similar debt of the same remaining maturities. The fair value measurement of long-term debt is categorized as level 1 as the inputs used reflect quoted prices in an active market.

December 31 (Canadian dollars in millions)	2011		2010	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt[1]	7,975	9,389	7,775	8,555

[1] The carrying value of long-term debt represents the par value of the notes and debentures. The fair value of long-term debt represents the market value of the notes and debentures, other than the MTN Series 14 Note, $500 million of the MTN Series 19 Note and $250 million of the MTN Series 21 Note, which are designated as part of hedging relationships and are therefore marked-to-market using the yield in the swap market for the related swaps.

Exposure to market risk, credit risk and liquidity risk arises in the normal course of the Company's business.

Market Risk

Market risk refers primarily to the risk of loss that results from changes in commodity prices, foreign exchange rates and interest rates. The Company does not have commodity risk. The Company does have foreign exchange risk as it enters into agreements to purchase materials and equipment associated with the Company's capital programs and projects that are settled in foreign currencies. This foreign exchange risk is not material, although the Company could in the future decide to issue foreign currency-denominated debt which would be hedged back to Canadian dollars consistent with Hydro One's risk management policy. Hydro One is exposed to fluctuations in interest rates as the regulated rate of return for the Company's transmission and distribution businesses is derived using a formulaic approach which is based on the forecast for long-term Government of Canada bond yields and the spread in 30-year "A"-rated Canadian utility bonds over the 30-year benchmark Government of Canada bond yield. The Company estimates that a 1% decrease in the forecasted long-term Government of Canada bond yield or the "A"-rated Canadian utility spread used in determining the Company's rate of return would reduce its Transmission Business' results of operations by approximately $18 million and its Hydro One Networks' Distribution Business' results of operations by approximately $10 million.

Credit Risk

Financial assets create credit risk that a counter-party will fail to discharge an obligation, causing a financial loss. As at December 31, 2011, there were no significant concentrations of credit risk with respect to any class of financial assets. The Company's revenue is earned from a broad base of customers. As a result, Hydro One did not earn a significant amount of revenue from any individual customer. As at December 31, 2011, there were no significant balances of accounts receivable due from any single customer.

In the year, the Company's provision for bad debts decreased to $18 million (2010 - $25 million). Adjustments and write-offs were determined on the basis of a review of overdue accounts, taking into consideration historical experience. As at December 31, 2011, approximately 3% of the Company's accounts receivable were aged more than 60 days.

Hydro One manages its counter-party credit risk through various techniques including entering into transactions with highly-rated counter-parties; limiting total exposure levels with individual counter-parties consistent with the Company's Board-approved Credit Risk Policy; entering into master agreements which enable net settlement and the contractual right of offset; and monitoring the financial condition of counter-parties. The Company's credit risk for accounts receivable is limited to the carrying amount on the Consolidated Balance Sheet.

The Company uses derivative financial instruments to manage interest-rate risk. Hydro One may enter into derivative agreements such as forward-starting pay fixed-interest-rate swap agreements to hedge against the effect of future interest rate movements on long-term fixed rate borrowing requirements. No such agreements were outstanding as at December 31, 2011.

Derivative financial instruments result in credit risk exposure of the counter-party involved for there is a risk of default by the counter-party of its obligation under these derivative instruments. As at December 31, 2011, the derivative instruments executed by Hydro One include: (a) two $250 million fixed-to-floating interest-rate swap agreements to convert $500 million of the 3.13% coupon note maturing November 19, 2014 into a three-month variable rate debt; (b) two $125 million fixed-to-floating interest-rate swap agreements to convert $250 million of the 2.95% coupon note maturing September 11, 2015 into a three-month variable rate debt; (c) two $250 million floating-to-fixed interest-rate swap agreements that lock in the floating rate the Company will pay for the next 12 months on the above fixed-to-floating interest-rate swaps; and (d) a $50 million floating-to-fixed interest-rate swap agreement that locks in the floating rate the Company will pay for the next 12 months on $50 million floating-rate debt. The counter-party credit risk exposure on the fair value of these interest-rate swap contracts is $36 million as at December 31, 2011 (2010 - $11 million).

Liquidity Risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Short-term liquidity is provided through cash and cash equivalents on hand, funds from operations, the Company's Commercial Paper Program, under which it is authorized to issue up to $1,000 million in short-term notes with a term to maturity of less than 365 days, the Company's revolving credit facility and through the Company's holdings of Province of Ontario Floating Rate Notes. The Commercial Paper Program is supported by a total of $1,500 million in liquidity facilities comprised of a $1,250 million committed revolving credit facility with a syndicate of banks maturing June 1, 2014 and the holding of $250 million of Province of Ontario Floating Rate Notes. The short-term liquidity under this program and anticipated levels of funds from operations should be sufficient to fund Hydro One's normal operating requirements.

As at December 31, 2011, accounts payable and accrued charges in the amount of $976 million are expected to be settled in cash at their carrying amounts within the next year. Long-term debt maturing over the next 12 months is $600 million. Interest payments over the next 12 months on the Company's outstanding long-term debt amount to $408 million.

As at December 31, 2011, Hydro One has issued long-term debt in the amount of $7,975 million and the Company is required to make interest payments in the amount of $6,779 million. Principal outstanding, interest payments and related weighted average interest rates are summarized by the number of years to maturity in the following table.

Years to Maturity	Principal Outstanding on Notes and Debentures *(Canadian dollars in millions)*	Interest Payments *(Canadian dollars in millions)*	Weighted Average Interest Rate *(Percent)*
1 year	600	408	5.8
2 years	600	373	5.0
3 years	750	343	3.1
4 years	550	320	2.8
5 years	450	295	4.6
	2,950	1,739	4.2
6 – 10 years	900	1,277	4.9
Over 10 years	4,125	3,763	5.8
	7,975	6,779	5.1

11. CAPITAL MANAGEMENT

The Company's objectives with respect to its capital structure are to maintain effective access to capital on a long-term basis at reasonable rates, and to deliver appropriate financial returns. In order to ensure ongoing effective access to capital, the Company targets an "A" category long-term credit rating.

The Company considers its capital structure to consist of shareholder's equity, short-term notes payable, long-term debt and cash and cash equivalents. The Company's capital structure as at December 31, 2011 and December 31, 2010 was as follows:

(Canadian dollars in millions)	**2011**	**2010**
Long-term debt payable within one year	600	500
Less: cash and cash equivalents	189	172
	411	328
Long-term debt	7,399	7,278
Preferred Shares	323	323
Common Shares	3,314	3,314
Retained Earnings	2,827	2,354
	6,464	5,991
Total Capital	14,274	13,597

For the purposes of this table and the Consolidated Statements of Cash Flows, "cash and cash equivalents" refers to the Consolidated Balance Sheet items "cash," "bank indebtedness" and "short-term investments."

The Company has customary covenants typically associated with long-term debt. Among other things, Hydro One's long-term debt and credit facility covenants limit the permissible debt to 75% of the Company's total capitalization, limit the ability to sell assets and impose a negative pledge provision, subject to customary exceptions. At December 31, 2011, Hydro One is in compliance with all of these covenants and limitations.

12. EMPLOYEE FUTURE BENEFITS

Hydro One has a contributory defined benefit pension plan covering all regular employees of Hydro One and its subsidiaries, except Hydro One Brampton. Employees of Hydro One Brampton participate in the Ontario Municipal Employees Retirement System, a multi-employer public sector pension fund. Current contributions by Hydro One Brampton are approximately $1 million annually.

Plan Asset Mix

Hydro One's pension plan asset mix at December 31, 2011 and 2010 was as follows:

	% of Plan Assets	
December 31	**2011**	**2010**
Equity securities	59.4	63.5
Debt securities	37.1	30.7
Other[1]	3.5	5.8
	100.0	100.0

[1] Composed of cash and cash investments.

Supplementary Information

The Hydro One pension plan holds $27 million of Hydro One Inc. corporate bonds (2010 - $14 million) and holds debt securities of the Province of $214 million at December 31, 2011 (2010 - $70 million).

The Company's pension plan provides benefits based on highest three-year average pensionable earnings. For new management employees who commenced employment on or after January 1, 2004, and for new Society of Energy Professionals hired after November 17, 2005, benefits are based on highest five-year average pensionable earnings. After retirement, pensions are indexed to inflation. The measurement date used to determine plan assets and the accrued benefit obligation is December 31. Based on the actuarial valuation filed with the Financial Services Commission of Ontario (FSCO) in September 2010, effective for December 31, 2009, the Company contributed $152 million to its pension plan in respect of 2011 (2010 - $193 million), $148 million of which is required to satisfy minimum funding requirements (2010 - $145 million). The Company made an additional payment of $48 million in December 2010 and an additional payment related to a partial plan wind-up in 2011 of $4 million. Contributions are payable one month in arrears. All of the contributions are expected to be in the form of cash. Contributions after 2012 will be based on an actuarial valuation effective December 31, 2012 and will depend on future investment returns, and changes in benefits or actuarial assumptions.

Total cash payments for employee future benefits made in 2011, consisting of cash contributed by the Company to its funded pension plan and cash payments directly to beneficiaries for its unfunded other benefit plans, was $195 million (2010 - $233 million).

	Pension		Employee Future Benefits other than Pension	
Year ended December 31 (Canadian dollars in millions)	**2011**	**2010**	**2011**	**2010**
Change in accrued benefit obligation				
Accrued benefit obligation, January 1	4,996	4,566	1,178	1,004
Current service cost	108	94	30	24
Interest cost	286	294	68	65
Reciprocal transfers	4	4	-	-
Benefits paid	(289)	(262)	(42)	(42)
Net actuarial loss (gain)	356	300	(28)	127
Accrued benefit obligation, December 31	5,461	4,996	1,206	1,178
Change in plan assets				
Fair value of plan assets, January 1	4,699	4,336	-	-
Actual return on plan assets	102	421	-	-
Reciprocal transfers	4	4	-	-
Benefits paid	(289)	(262)	-	-
Employer's contributions[1]	153	191	-	-
Employees' contributions	27	24	-	-
Administrative expenses	(14)	(15)	-	-
Fair value of plan assets, December 31	4,682	4,699	-	-
Funded status				
Unfunded benefit obligation	(779)	(297)	(1,206)	(1,178)
Unamortized net actuarial losses	1,238	746	115	144
Unamortized past service costs	7	11	8	11
Deferred pension asset (accrued benefit liability)	466	460	(1,083)	(1,023)
Less: current portion	-	-	43	43
Deferred pension asset (long-term liability)	466	460	(1,040)	(980)

[1] In January 2012, the Company made a contribution of $12 million in respect of 2011 (2011 - $13 million in respect of 2010).

Year ended December 31 (Canadian dollars in millions)	Pension 2011	Pension 2010	Employee Future Benefits Other Than Pension 2011	Employee Future Benefits Other Than Pension 2010
Components of net periodic benefit cost				
Current service cost, net of employee contributions	81	70	30	24
Interest cost	286	294	68	65
Actual return on plan assets net of expenses	(88)	(406)	-	-
Actuarial loss (gain)	356	300	(28)	127
Other	-	(1)	-	-
Costs arising in the period	635	257	70	216
Differences between costs arising in the period and costs recognized in the period in respect of:				
Return on plan assets	(202)	129	-	-
Actuarial (gain) loss	(289)	(236)	30	(134)
Plan amendments	4	4	3	4
Net periodic benefit cost	148	154	103	86
Charged to results of operations[2]	93	134	61	51
Effect of a 1% increase in health care cost trends on:				
Accrued benefit obligation, December 31	-	-	174	185
Service cost and interest cost	-	-	20	15
Effect of a 1% decrease in health care cost trends on:				
Accrued benefit obligation, December 31	-	-	(138)	(146)
Service cost and interest cost	-	-	(14)	(12)
Significant assumptions				
For net periodic benefit cost:				
Expected rate of return on plan assets	6.25%	6.50%	-	-
Weighted average discount rate	5.75%	6.50%	5.75%	6.50%
Rate of compensation scale escalation (without merit)	2.50%	2.50%	2.50%	2.50%
Rate of cost of living increase	2.00%	2.00%	2.00%	2.00%
Average remaining service life of employees *(years)*	11	10	11	11
Rate of increase in health care cost trend[3]	-	-	4.86%	4.81%
For accrued benefit obligation, December 31:				
Weighted average discount rate	5.25%	5.75%	5.25%	5.75%
Rate of compensation scale escalation (without merit)	2.50%	2.50%	2.50%	2.50%
Rate of cost of living increase	2.00%	2.00%	2.00%	2.00%
Rate of increase in health care cost trend[4]	-	-	4.51%	4.86%

[2] The Company follows the cash basis of accounting. During 2011, pension costs of $153 million (2010 - $191 million) were attributed to labour, of which $93 million (2010 - $134 million) was charged to operations and $60 million (2010 - $57 million) was capitalized as part of the cost of fixed assets.

[3] 8.31% in 2011 grading down to 4.86% per annum in and after 2029 (2010 - 8.57% in 2010 grading down to 4.81% per annum in and after 2029).

[4] 8.11% in 2012 grading down to 4.51% per annum in and after 2031 (2010 - 8.31% in 2011 grading down to 4.86% per annum in and after 2029).

13. ENVIRONMENTAL LIABILITIES

December 31 (Canadian dollars in millions)	PCB	LAR	Total
2011			
Opening balance, January 1	251	58	309
Interest accretion	12	2	14
Expenditures	(9)	(7)	(16)
Revaluation adjustment	(55)	5	(50)
Ending balance, December 31	199	58	257
Less: current portion	(13)	(9)	(22)
	186	49	235
2010			
Opening balance, January 1	262	65	327
Interest accretion	13	2	15
Expenditures	(9)	(8)	(17)
Revaluation adjustment	(15)	(1)	(16)
Ending balance, December 31	251	58	309
Less: current portion	(15)	(7)	(22)
	236	51	287

Estimated future environmental expenditures for each of the five years subsequent to December 31, 2011 and in total thereafter are as follows: 2012 - $22 million; 2013 - $24 million; 2014 - $36 million; 2015 - $25 million; 2016 - $23 million; and thereafter - $173 million. Of the total estimated future expenditures, $242 million relate to PCBs (2010 - $308 million) and $61 million to LAR (2010 - $61 million).

Consistent with its accounting policy for environmental costs, Hydro One records a liability for the estimated future expenditures associated with the removal and destruction of PCB-contaminated insulating oils and related electrical equipment and for the assessment and remediation of chemically-contaminated lands.

There are uncertainties in estimating future environmental costs due to potential external events such as changes in legislation or regulations and advances in remediation technologies. All factors used in estimating the Company's environmental liabilities represent management's best estimates of the present value cost required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. In addition, for the PCB program, the availability of critical resources such as skilled labour and replacement assets and the ability to take maintenance outages in critical facilities may influence the timing of expenditures. Estimated environmental liabilities are reviewed annually or more frequently if significant changes in regulation or other relevant factors occur. Estimate changes are accounted for prospectively.

In determining the amounts to be recorded as environmental liabilities, the Company estimates the current cost of completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future environmental expenditures have been discounted using factors ranging from 3.57% to 6.25%, depending on the appropriate rate for the period when increases in the obligations were first recorded.

PCBs

On September 17, 2008, Environment Canada published its final regulations governing the management, storage and disposal of PCBs. These regulations were enacted under the *Canadian Environmental Protection Act, 1999*. The regulations impose timelines for disposal of PCBs based on criteria including type of equipment, in-use status and PCB-contamination thresholds. All PCBs in concentrations of 500 parts per million (ppm) or more, except for

specified equipment, had to be disposed of by the end of 2009. However, in 2009, Hydro One sought and received an extension until 2014 for the removal of PCBs from certain station equipment that could potentially be contaminated in excess of this threshold. Under the regulations, PCBs in equipment in concentrations greater than 50 ppm and less than 500 ppm, or greater than 50 ppm for pole-top transformers, pole-top auxiliary electrical equipment and light ballasts must be disposed of by the end of 2025.

Management judges that the Company currently has very few PCB-contaminated assets in excess of 500 ppm. Priority will be given to targeting inspection and testing work toward identifying and removing PCBs in assets that must be compliant by 2014. Assets to be disposed of by 2025 primarily consist of pole-mounted distribution line transformers and light ballasts. Contaminated distribution and transmission station equipment will generally be replaced or will be decontaminated by removing PCB-contaminated insulating oil and retrofilling with replacement oil that is less than 2 ppm.

Management's best estimate of the total estimated future expenditures to comply with PCB regulations is about $242 million (2010 - $308 million). These expenditures are expected to be incurred over the period from 2012 to 2025. As a result of its most recent cost estimate to comply with existing PCB regulations, the Company reduced its December 31, 2010 PCB liability by approximately $55 million (2010 - $15 million) compared to the September 30 balance for the respective year.

LAR

As part of its annual review of environmental liabilities, the Company also reviewed its liability for LAR. As a result of this review, the Company increased its December 31, 2011 liability by approximately $5 million (2010 - decreased by $1 million) compared to the September 30 balance for the respective year. The Company's best estimate of the total future expenditures to complete its LAR program is about $61 million.

14. ASSET RETIREMENT OBLIGATIONS

Consistent with its accounting policy for asset retirement obligations, Hydro One records a liability for the present value of the estimated future expenditures associated with the retirement of tangible long-lived assets that the Company is legally required to remove. A corresponding amount is recorded as an asset retirement cost that is capitalized as part of the carrying amount of the related fixed asset.

There are uncertainties in estimating future expenditures due to potential external events such as changing legislation or regulations and advances in remediation technologies. All factors used in estimating the Company's asset retirement obligations represent management's best estimates of the costs required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. Asset retirement obligations are reviewed annually or more frequently if significant changes in regulation or other relevant factors occur. Estimate changes are accounted for prospectively.

In determining the amounts to be recorded as asset retirement obligations, the Company estimates the current fair value for completing required removal and remediation work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future expenditures have been discounted using factors ranging from approximately 3% to 5%, depending on the appropriate rate for the period when expenditures are expected to be incurred.

Hydro One has recorded a liability for the estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities. The Company's liability is based on management's best estimate of the present value of the estimated future expenditures to comply with existing regulations. In 2010, the Company completed a study with the aid of an expert external consultant to estimate the future expenditures required to remove asbestos prior to facility demolition. The current present value of the estimated future expenditures is $7 million. The amount of interest recorded is nominal and there have been no expenditures associated with this obligation.

In 2011, Hydro One recorded a $4 million asset retirement obligation related to the future decommissioning and removal of one of its switching stations. Including the obligation recorded in respect of another switching station in 2010, the present value of the estimated future expenditures to discharge these obligations is about $8 million. Interest recorded on this amount in the year was nominal and there have been no expenditures associated with these obligations to date.

15. SHARE CAPITAL

Common and Preferred Shares

On March 31, 2000, the Company issued to the Province 12,920,000 5.5% cumulative preferred shares with a redemption value of $25 per share, and 99,990 common shares, bringing the total number of outstanding common shares to 100,000. The Company is authorized to issue an unlimited number of preferred and common shares.

The preferred shares are entitled to an annual cumulative dividend of $18 million, which is payable on a quarterly basis. The preferred shares are redeemable at the option of the Province at a price of $25 per share, representing the stated value, plus any accrued and unpaid dividends if the Province sells a number of the common shares which it owns to the public such that the Province's holdings are reduced to less than 50% of the common shares of the Company. Hydro One may elect, without condition, to pay all or part of this redemption price by issuing additional common shares to the Province. If the Province does not exercise its redemption right, the Company would have the ability to adjust the dividend on the preferred shares to produce a yield that is 0.50% less than the then-current dividend market yield for similarly rated preferred shares. The preferred shares do not carry voting rights, except in limited circumstances, and would rank in priority over the common shares upon liquidation.

Dividends

Common dividends are declared at the sole discretion of the Hydro One Board of Directors, and are recommended by management based on results of operations, maintenance of the deemed regulatory capital structure, financial condition, cash requirements and other relevant factors such as industry practice and shareholder expectations.

In 2011, preferred dividends in the amount of $18 million (2010 - $18 million) and common dividends in the amount of $150 million (2010 - $10 million) were declared.

Earnings per Share

Earnings per share is calculated as net income during the year, after cumulative preferred dividends, divided by the weighted average number of common shares outstanding during the year.

16. RELATED PARTY TRANSACTIONS

The Province, OEFC, IESO, Ontario Power Authority (OPA) and Ontario Power Generation Inc. (OPG) are related parties of Hydro One. In addition the OEB is related to the Company by virtue of its status as a Provincial Crown Corporation. Transactions between these parties and Hydro One were as follows:

Hydro One received revenue for transmission services from the IESO, based on uniform transmission rates approved by the OEB. Transmission revenue for 2011 includes $1,366 million (2010 - $1,277 million) related to these services. Hydro One receives amounts for rural rate protection from the IESO. Distribution revenue for 2011 includes $127 million (2010 - $127 million) related to this program. Hydro One also received revenue from the IESO related to the supply of electricity to remote northern communities. Distribution revenue for 2011 includes $28 million (2010 - $28 million) related to these services.

In 2011, Hydro One purchased power in the amount of $2,401 million (2010 - $2,361 million) from the IESO-administered electricity market, $16 million (2010 - $19 million) from OPG and $10 million (2010 - $13 million) from the OEFC.

Under the *Ontario Energy Board Act, 1998*, the OEB is required to recover all of its annual operating costs from gas and electricity distributors and electricity transmitters. In 2011, Hydro One incurred $11 million (2010 - $11 million) in OEB fees.

Hydro One has service level agreements with the other successor corporations of Ontario Hydro. These services include field, engineering, logistics and telecommunications services. Revenues related to the provision of construction and equipment maintenance services to the other successor corporations were $11 million (2010 - $14 million), primarily for the Transmission Business. Operation, maintenance and administration costs related to the purchase of services from the other successor corporations were less than $2 million in each of 2011 and 2010.

The OPA funds substantially all of the Company's Conservation Demand Management (CDM) programs. The funding includes program costs, incentives, management fees and bonuses. In 2011, Hydro One received $39 million from the OPA in respect of the CDM programs (2010 - $36 million).

The provision for PILs, property taxes and capital taxes were paid or payable to the OEFC and dividends were paid or payable to the Province.

The amounts due to and from related parties as a result of the transactions referred to above are as follows:

December 31 (Canadian dollars in millions)	2011	2010
Accounts receivable	143	111
Accounts payable and accrued charges	(344)	(283)

Included in accounts payable and accrued charges are amounts owing to the IESO in respect of power purchases of $209 million (2010 - $222 million).

17. CONSOLIDATED STATEMENTS OF CASH FLOWS

For the purposes of the Consolidated Statements of Cash Flows, "cash and cash equivalents" refers to the Consolidated Balance Sheet items "cash", "short-term investments" and "bank indebtedness." The changes in non-cash balances related to operations consist of the following:

Year ended December 31 (Canadian dollars in millions)	2011	2010
Accounts receivable increase	(38)	(51)
Materials and supplies increase	(4)	-
Accounts payable and accrued charges increase	188	87
Accrued interest increase	1	10
Long-term accounts payable and other liabilities decrease	-	(3)
Employee future benefits other than pension increase	60	40
Other	(11)	11
	196	94
Supplementary information:		
Interest paid	413	409
Payments in lieu of corporate income taxes	80	48

18. CONTINGENCIES

Legal Proceedings

Hydro One is involved in various lawsuits, claims and regulatory proceedings in the normal course of business. In the opinion of management, the outcome of such matters will not have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

Transfer of Assets

The transfer orders by which Hydro One acquired certain of Ontario Hydro's businesses as of April 1, 1999 did not transfer title to some assets located on lands held for bands or bodies of Indians under the *Indian Act* (Canada). Currently, the OEFC holds these assets. Under the terms of the transfer orders, Hydro One is required to manage these assets until it has obtained all consents necessary to complete the transfer of title of these assets to itself. The Company cannot predict the aggregate amount that it may have to pay, either on an annual or one-time basis, to obtain the required consents. However, it anticipates having to pay more than the $1,142,743 that it paid to these Indian bands and bodies in 2011. If Hydro One cannot obtain consents from the Indian bands and bodies, the OEFC will continue to hold these assets for an indefinite period of time. If the Company cannot reach a satisfactory settlement, it may have to relocate these assets from the Indian lands to other locations at a cost that could be substantial or, in a limited number of cases, to abandon a line and replace it with diesel-generation facilities. The costs relating to these assets could have a material adverse effect on the Company's net income if it is not able to recover them in future rate orders.

19. COMMITMENTS

Agreement with Inergi LP (Inergi)

Effective March 1, 2002, Inergi (a wholly-owned subsidiary of Cap Gemini Canada Inc.) began providing services to Hydro One. On May 1, 2010, consistent with the terms of the contract, the Company extended the Master Services Agreement with Inergi for a further three-year period, to expire on February 28, 2015. As a result of this agreement, Hydro One receives from Inergi a range of services including business processing and information technology outsourcing services, as well as core system support related primarily to SAP implementation and optimization. Inergi billings for these services have ranged between $93 million and $130 million per year and are subject to external benchmarking every three years to ensure Hydro One is receiving a defined, competitive and continuously improved price. In connection with this agreement, on March 1, 2002 the Company transferred approximately 900 employees to Inergi, including about 130 non-regular employees.

The annual commitments under the agreement in each of the five years subsequent to December 31, 2011, and in total thereafter are as follows: 2012 - $138 million; 2013 - $133 million; 2014 - $128 million; 2015 - $21 million; 2016 and thereafter - $nil.

Prudential Support

Purchasers of electricity in Ontario, through the IESO, are required to provide security to mitigate the risk of their default based on their expected activity in the market. As at December 31, 2011, the Company provided prudential support to the IESO on behalf of Hydro One Networks and Hydro One Brampton using only parental guarantees of $325 million. Prudential support at December 31, 2011 was also provided on behalf of two distributors using guarantees of $660 thousand. The IESO could draw on these guarantees if these subsidiaries or distributors fail to make a payment required by a default notice issued by the IESO. The maximum potential payment is the face value of any bank letters of credit plus the nominal amount of the corporate guarantee. If Hydro One's highest long-term credit rating deteriorated to below the "Aa" category, the Company would be required to resume providing letters of credit as prudential support.

Retirement Compensation Arrangements

Bank letters of credit have been issued to provide security for the Company's liability under the terms of a trust fund established pursuant to the supplementary pension plan for the employees of Hydro One and its subsidiaries. The trustee is required to draw upon the letters of credit if Hydro One is in default of its obligations under the terms of this plan. Such obligations include the requirement to provide the trustee with an annual actuarial report as well as letters of credit sufficient to secure the Company's liability under the plan, to pay benefits payable under the plan and to pay the letter of credit fee. The maximum potential payment is the face value of the bank letters of credit. As at December 31, 2011, Hydro One had bank letters of credit of $124 million (2010 - $113 million) outstanding relating to retirement compensation arrangements.

Operating Leases

The future minimum lease payments under operating leases for each of the five years subsequent to December 31, 2011, and in total thereafter are as follows: 2012 - $8 million; 2013 - $8 million; 2014 - $8 million; 2015 - $3 million; 2016 - $7 million; and thereafter - $20 million.

20. SEGMENT REPORTING

Hydro One has three reportable segments:

- The Transmission Business, which comprises the core business of providing transportation and connection services, is responsible for transmitting electricity throughout the Ontario electricity grid;
- The Distribution Business, which comprises the core business of delivering and selling electricity to customers; and
- The "other" segment, the operations of which primarily consist of those of the telecommunications business.

The designation of segments is based on a combination of regulatory status and the nature of the products and services provided. The accounting policies followed by the segments are the same as those described in the summary of significant accounting policies (see Note 2). Segment information on the above basis is as follows:

Year ended December 31 (Canadian dollars in millions)	**Transmission**	**Distribution**	**Other**	**Consolidated**
2011				
Segment profit				
Revenues	1,389	4,019	63	5,471
Purchased power	-	2,628	-	2,628
Operation, maintenance and administration	422	609	61	1,092
Depreciation and amortization	302	304	10	616
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	665	478	(8)	1,135
Financing charges				344
Income before provision for payments in lieu of corporate income taxes				791
Capital expenditures	810	628	9	1,447

Year ended December 31 (Canadian dollars in millions)	**Transmission**	**Distribution**	**Other**	**Consolidated**
2010				
Segment profit				
Revenues	1,307	3,754	63	5,124
Purchased power	-	2,474	-	2,474
Operation, maintenance and administration	416	602	60	1,078
Depreciation and amortization	273	300	10	583
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	618	378	(7)	989
Financing charges				342
Income before provision for payments in lieu of corporate income taxes				647
Capital expenditures	936	629	5	1,570

December 31 (Canadian dollars in millions)	**2011**	**2010**
Total assets		
Transmission	10,380	9,805
Distribution	7,336	6,908
Other	652	609
	18,368	17,322

All revenues, costs and assets, as the case may be, are earned, incurred or held in Canada.

21. SUBSEQUENT EVENTS

On January 13, 2012, Hydro One issued $300 million in 3.20% notes under its MTN Program with a maturity date of January 13, 2022.

On February 10, 2012, Hydro One declared common dividends to its shareholder in the amount of $277 million and preferred shares of $4 million.

22. COMPARATIVE FIGURES

The comparative Consolidated Financial Statements have been reclassified from statements previously presented to conform to the presentation of the December 31, 2011 Consolidated Financial Statements.

HYDRO ONE INC.
FIVE-YEAR SUMMARY OF FINANCIAL AND OPERATING STATISTICS

Year ended December 31 (Canadian dollars in millions)	2011	2010	2009	2008	2007
Statement of operations data					
Revenues					
Transmission	1,389	1,307	1,147	1,212	1,242
Distribution	4,019	3,754	3,534	3,334	3,382
Other	63	63	63	51	31
	5,471	5,124	4,744	4,597	4,655
Costs					
Purchased power	2,628	2,474	2,326	2,181	2,240
Operation, maintenance and administration	1,092	1,078	1,057	965	995
Depreciation and amortization	616	583	537	548	521
	4,336	4,135	3,920	3,694	3,756
Income before financing charges and provision for payments in lieu of corporate income taxes	1,135	989	824	903	899
Financing charges	344	342	308	292	295
Income before provision for payments in lieu of corporate income taxes	791	647	516	611	604
Provision for payments in lieu of corporate income taxes	150	56	46	113	205
Net income	641	591	470	498	399
Basic and fully diluted earnings per common share *(Canadian dollars)*	6.228	5.727	4.528	4.797	3.809
December 31 (Canadian dollars in millions)					
Balance sheet data					
Assets					
Transmission	10,380	9,805	8,993	7,877	7,273
Distribution	7,336	6,908	6,481	5,873	5,407
Other	652	609	161	128	106
Total assets	18,368	17,322	15,635	13,878	12,786
Liabilities					
Current liabilities (including current portion of long-term debt)	1,820	1,540	1,655	1,300	1,452
Long-term debt	7,399	7,278	6,281	5,733	5,063
Other long-term liabilities	2,695	2,523	2,281	1,721	1,385
Shareholder's equity					
Share capital	3,637	3,637	3,637	3,637	3,637
Retained earnings	2,827	2,354	1,791	1,497	1,258
Accumulated other comprehensive income	(10)	(10)	(10)	(10)	(9)
Total liabilities and shareholder's equity	18,368	17,322	15,635	13,878	12,786

HYDRO ONE INC.
FIVE-YEAR SUMMARY OF FINANCIAL AND OPERATING STATISTICS (continued)

Year ended December 31 (Canadian dollars in millions)	2011	2010	2009	2008	2007
Other financial data					
Capital expenditures					
Transmission	810	936	918	704	560
Distribution	628	629	643	570	511
Other	9	5	5	10	20
Total capital expenditures	1,447	1,570	1,566	1,284	1,091
Ratios					
Net asset coverage on long-term debt[1]	1.81	1.77	1.79	1.84	1.87
Earnings coverage ratio[2]	2.71	2.39	2.15	2.63	2.67
Operating statistics					
Transmission					
Units transmitted *(TWh)*[3]	141.5	142.2	139.2	148.7	152.2
Ontario 20-minute system peak demand *(MW)*[3]	25,505	25,145	24,477	24,231	25,809
Ontario 60-minute system peak demand *(MW)*[3]	25,450	25,075	24,380	24,195	25,737
Total transmission lines *(circuit-kilometres)*	28,942	28,951	28,924	29,039	28,915
Distribution					
Units distributed to Hydro One customers *(TWh)*[3]	29.2	29.1	28.9	29.9	30.2
Units distributed through Hydro One lines *(TWh)*[3,4]	42.5	42.5	43.5	44.7	45.7
Total distribution lines *(circuit-kilometres)*	120,514	123,552	123,528	123,260	122,933
Customers	1,365,379	1,345,177	1,333,920	1,325,745	1,311,714
Total regular employees	5,781	5,717	5,427	5,032	4,602

[1] The net asset coverage on long-term debt ratio is calculated as total assets minus total liabilities excluding long-term debt (including current portion) divided by long-term debt (including current portion).

[2] The earnings coverage ratio has been calculated as the sum of net income, financing charges and provision for payments in lieu of corporate income taxes divided by the sum of financing charges, capitalized interest and cumulative preferred dividends.

[3] System-related statistics include preliminary figures for December.

[4] Units distributed through Hydro One lines represent total distribution system requirements and include electricity distributed to consumers who purchased power directly from the IESO.